Eric J. Hanson

Dynamic Decade

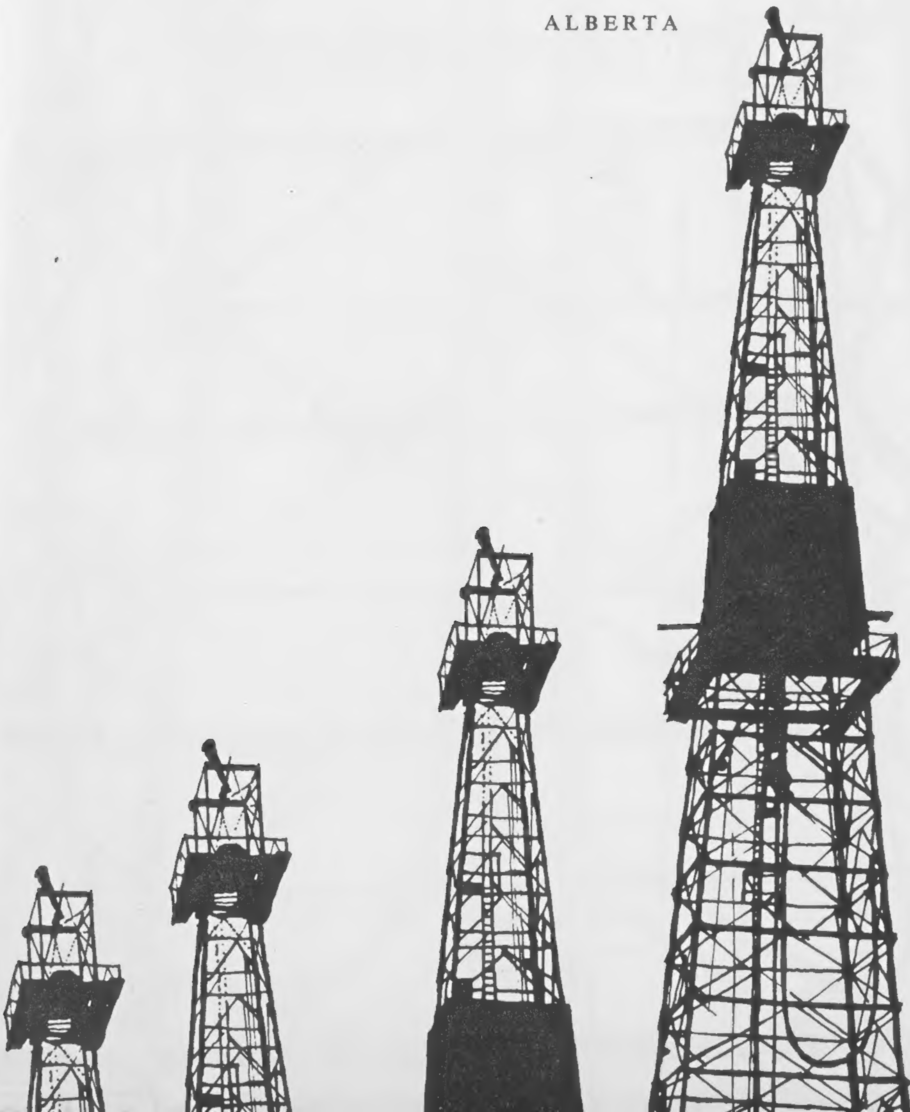
McClelland
& Stewart

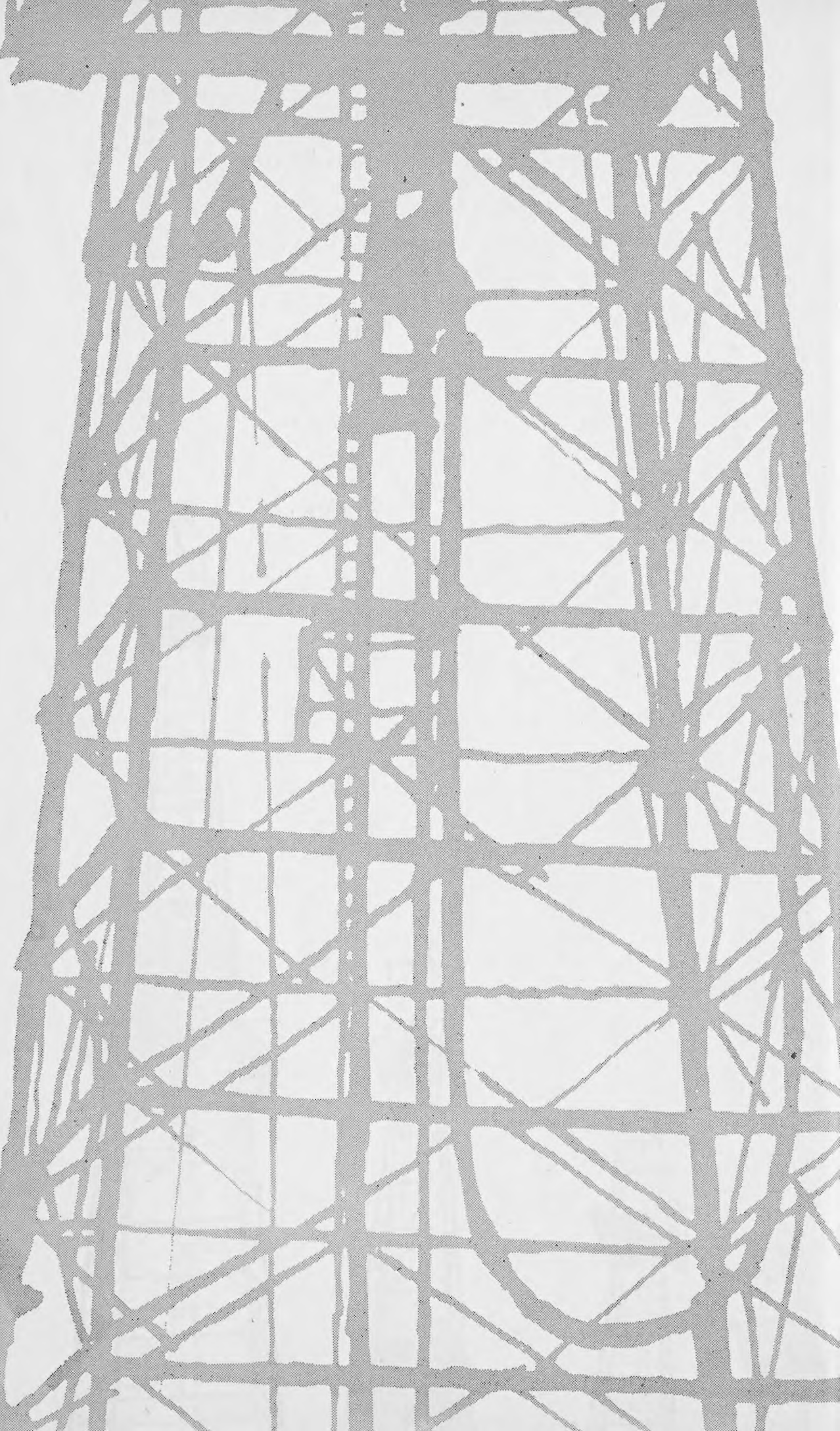
D. G. MacEachern

18—

Dynamic **DECADE**

THE EVOLUTION AND EFFECTS OF THE OIL INDUSTRY IN ALBERTA





Eric J. HANSON
Professor of Economics
University of Alberta

Dynamic DECADE

published by *McCLELLAND*
&
STEWART
LIMITED
Toronto

Copyright in Canada Eric J. Hanson, 1958

The mural by R. York Wilson in the Imperial Oil Building is reproduced on the jacket by permission of The Imperial Oil Company.

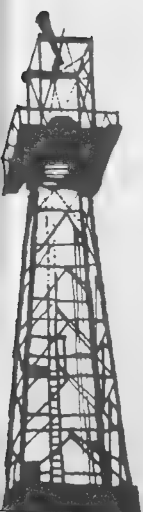
Designed by Frank Newfeld

Printed and bound in Canada T. H. Best Printing Company, Ltd.
Don Mills, Ont.

to

my

parents



Preface

The discovery and development of petroleum in Alberta brought profound and extensive changes in the provincial economy in the short space of the decade 1946-1956. In these years Alberta changed dramatically from a dormant economic society that had little growth prospect into a rapidly expanding and vigorous society. It is this profound change which my book examines.

The stage is set by the long history of oil developments in the province which proceeded very slowly up to 1946. With the bringing in of Wildcat No. 134 a new era opened. From that time on there was an ever-growing fund of men and money pouring into the province. Effects on income and employment were nothing less than startling. It is the object of this work to analyze and measure the proportions of these great flows and place the Alberta economy of 1957 in some perspective.

This dynamic decade has set the stage for a series of future developments that will unfold as the years progress. There may be—indeed, there will be—the occasional lapse. None the less, the events that have occurred thus far give us assurance of a great future both for the oil industry itself and for the many secondary and tertiary industrial activities that will develop as the scene unfolds.

To provide estimates of the contribution of the petroleum industry to the income of Alberta since 1947 much statistical material had to be collected and analyzed. Income is the life blood of an economy. In large, highly self-sufficient economies such as that of the United States, the flow of income depends mainly upon rates of spending within the economy. In small, specialized regional economies such as that of Alberta, exports and imports are large in relation to total production. The level of regional income is highly dependent upon the inflow of funds from outside the region. This inflow consists of receipts from exports of goods and services and of capital to be invested in the region by non-residents. Conversely, the high level of imports leads to an outflow of funds. The author's task was that of analyzing both inflows and outflows of funds to estimate the importance of the petroleum industry in the Alberta economy.

In the interests of the general reader it appeared desirable to keep the technical discussions of the petroleum industry and the methodology of income analysis to a minimum. Hence there are few footnotes, and large explanatory sections of text were discarded in successive drafts. Various

special aspects of both the petroleum industry and the region presented themselves in the course of the study. For example, questions pertaining to taxation of the petroleum industry, pricing and prorationing of crude oil, land policies of the provincial government and implications of economic growth were found to be altogether too large in scope and detail to be analyzed in this volume. The author found that to do justice to each question would require the writing of special treatises which would detract from the purposes at hand. The bibliography provides indications of the methods and scope of this study.

My most immediate debt is to Dr. Herman Otte, Professor of Economic Geography, Graduate School of Business Administration, Columbia University, New York. Professor Otte read the manuscript at various stages, provided guidance and assistance in many ways and gave continuous encouragement throughout a very busy period.

The writer acknowledges the invaluable information, insights and suggestions provided by the personnel of the Canadian Petroleum Association and of many oil companies, both large and small, integrated and independent, who were interviewed during the course of the study. He is also indebted to several financial institutions such as James Richardson and Sons, the Royal Bank of Canada and the Canadian Bank of Commerce for providing data on the Alberta petroleum industry. A long list of names of persons and companies would be required to provide full acknowledgment of the extent to which the author was assisted by the petroleum industry.

Colleagues of the author were helpful in discussions of concepts and ideas, and he is particularly indebted to Professor W. D. Gainer of the University of Alberta and Professor G. F. MacDowell, presently of Brandon College. Mr. Dan Istvanffy and Mr. William Brese of the Alberta Bureau of Statistics furnished provincial data without which the study could not have been completed satisfactorily. The Dominion Bureau of Statistics was also a valuable source of information. Mr. Vernon Millard and Mr. Cecil Jackman of the Alberta Petroleum and Natural Gas Conservation Board assisted greatly in providing data on the petroleum industry in Alberta. Mr. James Sherbaniuk, University of Alberta, did useful research during the initial stages of the study and in collaboration with the Edmonton District Planning Commission.

Special acknowledgment is due Imperial Oil Limited which provided financial assistance in the form of a grant to the University of Alberta. This made it possible for the university to release the author from his normal duties for a year to concentrate on the completion of this study.

I wish to thank the Canadian Institute of International Affairs for permission to reprint material from my article "Natural Gas in Canadian-

American Relations", which originally appeared in *The International Journal*.

Thanks are due the various people who typed the successive drafts of the manuscripts, and to Mrs. Joanne Purkis and Miss Lena Schultz in particular. The writer was fortunate in obtaining the services of Mr. Klaus Wirtz, Project Division, City of Toronto, who drew most of the maps and charts.

Eric J. Hanson,
University of Alberta
October 1, 1957.

Foreword

The past decade in Canada has been marked by extraordinary development of mineral, forest and power resources. Giant projects, centred on resource development, extend from the Atlantic to the Pacific and in various localities they stretch northward deep into the sub-Arctic Zone. No undertakings exemplify this development better than the oil and natural gas industries of Alberta and their meteoric rise to world prominence. This book, as Professor Hanson notes in his Preface, examines "profound and extensive changes in the provincial economy" and attempts to estimate the income flows generated by the petroleum industry.

Certain areas producing substantial volumes of petroleum and natural gas are drawing an increasing variety of affiliated industries and are stimulating service activities. An important reason for such attractions is the diversification of products derived from petroleum and natural gas. New products stimulate the rise of new industries with great growth potential, and these industries, other things being equal, tend to be drawn to certain areas producing petroleum and natural gas. Examples of such "new" developments are the petrochemical industries and power-oriented industries supplied with petroleum and natural gas, at low cost, from nearby producing fields. Industries furnishing supplies and services are in turn attracted. In this manner purchases by the petroleum and natural gas industries and their affiliated industries reach out and call into being additional transportation facilities and suppliers of equipment and materials such as steel pipe, cement and portable power machinery until virtually all sectors of the economy have been advanced.

The Province of Alberta, Canada, provides a striking contemporary example of this compounding process in action. There, free competitive enterprise, developing the oil and natural gas resources, has energized a decade of economic advances unmatched even in other leading growth-provinces of Canada. This is the central theme of Professor Hanson's book. It systematically describes and analyzes the far-reaching and beneficial impact of petroleum and natural gas development in Alberta. The latter part of the book traces and estimates this impact quantitatively beyond any previous study concerned with a similar theme.

Herman F. Otte
Graduate School of Business Administration
Columbia University, New York, N.Y.
September, 1957.

Contents

List of abbreviations

ABS	Alberta Bureau of Statistics, Department of Industries and Labour, Government of Alberta
API	American Petroleum Institute
CPA	Canadian Petroleum Association
DBS	Dominion Bureau of Statistics, Government of Canada
Gordon Commission	The convenient term used to describe the Royal Commission on the Economic Prospects of Canada, appointed in 1955 by the Government of Canada under the chairmanship of Mr. W. L. Gordon
PNGCB	The Petroleum and Natural Gas Conservation Board, Government of Alberta

Dynamic **DECADE**

1

Introduction

Oil has played an essential role in promoting the remarkable economic progress of the world during the postwar era. It has made possible the use of a great many machines and processes that have brought about great increases in productivity. The petroleum industry, too, has become a very important international industry which has stimulated economic development in various parts of the globe.

A striking aspect of the postwar years is the great increase in world crude oil consumption. Crude oil has been produced commercially for one hundred years, but of the total output for the century, more than half has been brought to the surface since the end of the Second World War. In 1956 the world consumption of crude oil exceeded six billion barrels, more than double the 1946 total. Fig. 1 illustrates the difference in demand in 1946 and 1956. Rapid industrialization, war reconstruction programs, relatively high investment costs involved in adding to coal and water-power production, and the rapid increase in world crude oil reserves have been joint factors inducing the large postwar increases in the world demand for crude oil.

To provide adequate supplies to meet the growing world demand, the search for oil was intensified throughout the world during the postwar years. More than twice as many wells were drilled in the world in 1956 as in 1946. The capital expenditure of the petroleum industry in the United States and the rest of the free world rose from $2.7 billion to $8.2 billion from 1946 to 1955, a threefold increase. During this decade, total capital expenditures exceeded $56 billion of which $18 billion was spent outside the United States.

The search has not been in vain. In the United States, proven recoverable crude oil reserves discovered have averaged about three billion barrels annually since 1946. The rise in the reserves of the Middle East is almost unbelievable. Between 1947 and 1956 the unproduced proven reserves

of the world amounted to a little more than 60 billion barrels, fairly evenly divided among the United States, the Middle East and the rest of the world. In 1956 world recoverable reserves totalled an estimated 200 billion barrels with about two thirds in the Middle East, less than one sixth in the United States and almost one fifth in the rest of the world. Fig. 2 illustrates the increases in the world reserves in 1947-1956.*

The great increase in the reserves of the Middle East has done much to make the present high level of world crude oil consumption possible. The Middle East has also become the current cauldron of international affairs. The United States, however, continues to be the leading producer despite a fall in its contribution from nearly two thirds of world output in 1945 to a little more than two fifths in 1956. The Middle East share grew from one tenth to one fifth during the same period. South America, chiefly Venezuela, provided a steady one sixth throughout the years in question.

There are few, if any, countries in which the production and consumption of crude oil and its products balance each other. Europe and North America are the main deficit areas and they import large quantities of oil, chiefly from the two great surplus areas of the world, the Middle East and South America. Africa, Australia, New Zealand, most countries of the Far East, including industrial Japan, have to import almost all their requirements. As a result, crude oil and its products constitute a most important group of commodities entering into international trade as imports and exports. Large tanker fleets carry the bulk of the products with pipe lines playing a subsidiary role. The pattern of this trade has undergone continuous change since the turn of the century as new discoveries have been made, consumption has risen at varying rates in different countries, wars have been fought, international incidents have occurred and oil production and transportation systems have been improved.

There are few countries in which the pattern has changed so rapidly in a decade as in Canada. The change has been induced largely by great discoveries of crude oil in the Province of Alberta. Only ten years ago the Canadian petroleum industry consisted mainly of manufacturing and marketing operations based upon crude oil and products imported from the United States and from Venezuela and the West Indies. In Alberta the industry did have producing operations, but the output was relatively small and was sufficient to satisfy only the regional market. Today the Canadian industry is not only much more integrated in its operations than ten years ago, but it is also much more integrated in a national geographic fashion. It still imports crude oil to serve the Atlantic provinces and the Montreal market area, but in the rest of the country it utilizes Alberta

*In mid-1957 world reserves were estimated at 231 billion barrels.

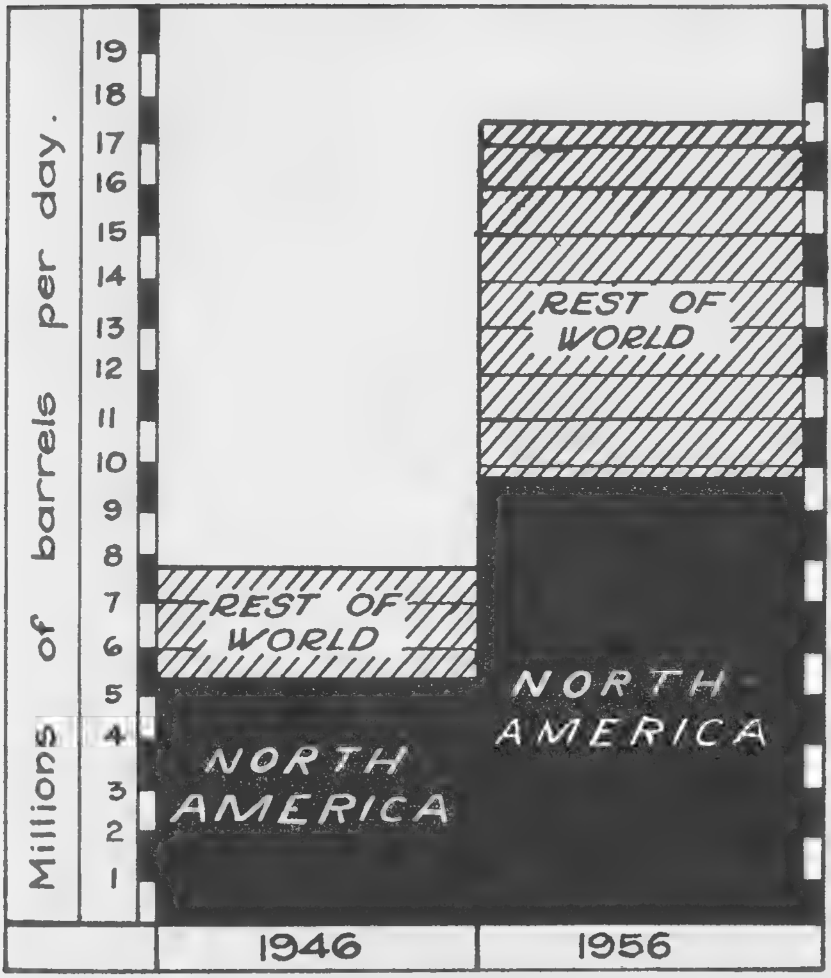


Fig. 1 Daily demand for crude oil in the world, 1946 and 1956
Note: "Rest of the World" includes USSR Source: *World Oil*

crude oil, transported by pipe lines, and supplemented to some extent by production from Saskatchewan and Manitoba fields. Considerable quantities of crude oil are exported to the northwestern and midwestern regions of the United States. The petroleum industry has become a significant contributing and unifying sector of the Canadian economy.

In Canada the rise of oil as a source of primary energy has been spectacular since the end of the war. In 1945 oil provided less than one quarter of the total primary energy consumed; in 1955 it accounted for one half of a total which was 50 per cent larger than that of 1945. Natural gas,

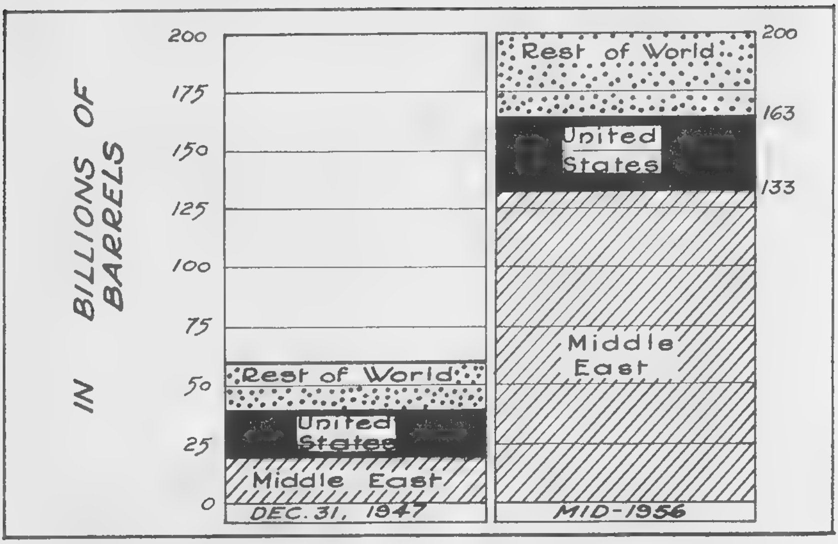


Fig. 2 World crude oil reserves, December 31, 1947 and mid-1956
Source: *World Oil*

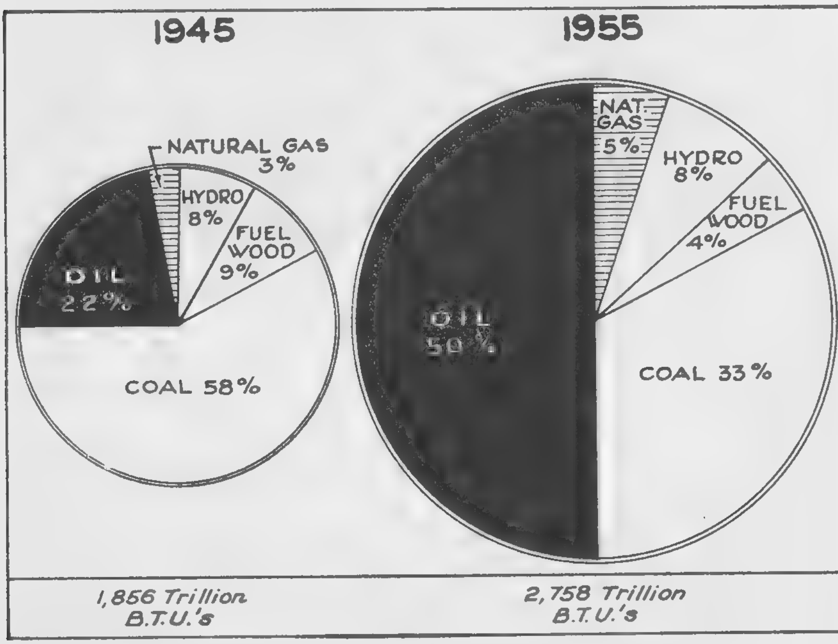


Fig. 3 Canadian consumption of primary energy, 1945 and 1955

consumed mainly in Alberta, increased its contribution from three to five per cent. Fig. 3 shows the contributions of oil, natural gas, coal, hydro and fuel wood in 1945 and 1955. The shift to petroleum sources is obvious, and once Alberta's great natural gas potential is unlocked from its reservoirs and transported to eastern and western markets the trend will be accelerated.

The following table indicates the great changes that have occurred in Canadian crude oil production, imports and exports during the "petroleum decade" 1946-56:

Thousands of barrels per day	1946	1956
Production		
Crude oil only	21	478
Imports		
Crude oil and products	201	396
Exports		
Crude oil and products	0	126

Since 1946 Canadian production has risen more than twentyfold and consumption more than three times. Imports have almost doubled to meet the needs of the eastern Canadian market area which Alberta crude has not been able to reach on an economic basis. Offsetting these imports, however, exports to the United States began in 1951, and in 1956 they attained a level six times that of the total Canadian production in 1946 and more than one fourth of the 1956 output. Fig. 4 shows the evolution of Canadian crude-oil self-sufficiency for the whole decade. In 1946 the nation produced only one tenth of its requirements; in 1956 it produced almost two thirds.

All of this may not be impressive against the backdrop of world production and consumption. Between 1946 and 1956 Canadian output of crude oil rose from 0.3 per cent to nearly three per cent of the world output, and consumption increased from about three to more than four per cent of that of the world. But Canada had only about two thirds of a per cent of the world population during the decade. In 1956 it produced more than ten barrels of crude oil per person, five times the world average of a little more than two barrels; in 1946 Canadian consumption per person was 6.6 barrels, the second highest in the world after the United States with 12.7 barrels and far above the world average of a little more than one barrel. By 1956 Canadian consumption had climbed to more than 16 barrels per person, not far behind the United States average of nearly twenty barrels and almost eight times the world average. Seen in this light, the Canadian petroleum industry is most important and on a relative basis is growing up to its uncle in the United States.

The petroleum industry has done much to make the Canadian dollar one of the hard currencies of the world. The discovery of oil in Alberta has reduced the need for imported oil; it has provided Canada with a new export industry; it has induced a large volume of investment in Canada. During the 1950's the value of crude oil imports has been held at a level not far above $200 million annually. As against this, the value of exports exceeded $100 million in 1956. In addition, there has been an inflow of foreign capital into the industry, chiefly from the United States, averaging about $200 million per year for the decade 1947-56.

The oil discoveries of the last decade increased Canadian oil consumption for two reasons. Without these discoveries there would have been fewer people in Canada and high-cost crude oil would have restricted consumption, particularly in Western Canada. Even after allowing for a smaller Canadian economy and the rationing effects of high-cost imported crude oil in Western Canada, the value of imports of oil would have been about half a billion dollars or more with no oil exports and relatively little foreign investment in the petroleum industry to offset the outflow of funds. There could well have been a most critical foreign exchange situation. Indeed, the Canadian postwar development would have been considerably less spectacular without the expansion which took place in the petroleum industry. The oil discoveries in Alberta also did much to advertise to foreign investors the investment potential in Canada in both petroleum and non-petroleum ventures.

Through its investing and operating activities the petroleum industry has added directly, in substantial measure, to the population and national income of Canada. Indirectly, through the stimulation provided by its investment and operational spending and by its cost-reducing efforts in providing crude oil and its products, the industry induced much new investment and production in other industries in Canada. The effects upon the Canadian economy of the development of the petroleum industry have been great and far-reaching during the last decade.

But if the effects of the petroleum industry upon the Canadian economy have been large, they have been relatively larger in Alberta, the region in which so much of the Canadian petroleum development has been concentrated. It is in Alberta that the main Canadian discoveries of oil were made in 1947-56. The province produced more than nine tenths of the small Canadian output of crude oil in 1946; it continued to do so as output expanded rapidly with the accelerating tempo of discoveries within its borders. In recent years its neighbours, Saskatchewan and Manitoba, have been significant producers. But even in 1956 Alberta produced four fifths of Canada's output of crude oil and more than nine tenths of the Canadian production of natural gas. It possessed about three quarters of

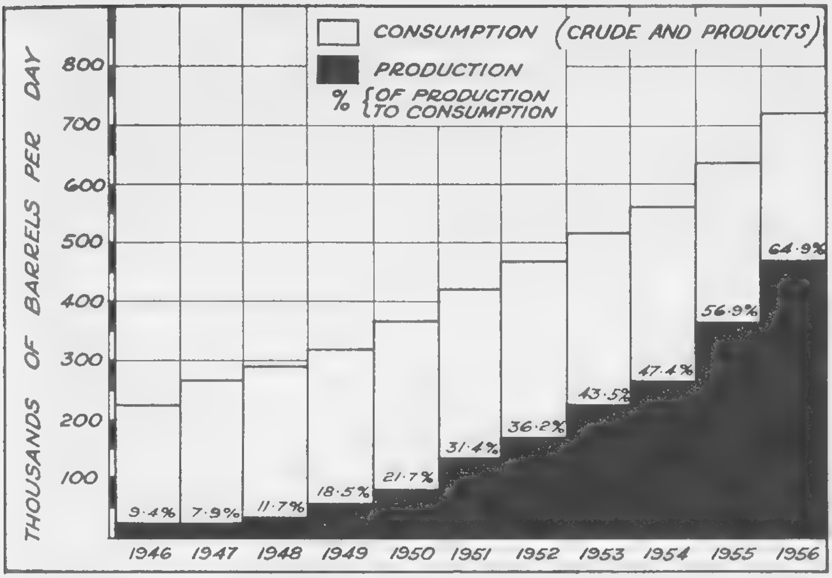


Fig. 4 Consumption and production of crude oil in Canada, 1946-56 (thousands of barrels per day)

estimated Canadian reserves of crude oil and more than four fifths of estimated Canadian reserves of natural gas.

Petroleum discoveries have played an important part in the economic development of North America. They have led to the creation of new regional industries and occupations and to increases in the population, income, wealth and prestige of the regions concerned.

Few petroleum discoveries have had such marked effects upon a large regional economy as those which took place in Alberta. Out of the four billion dollars invested in Canada by the petroleum industry in 1947-56, almost two and a half billion dollars were invested in Alberta. It has generated much income in Alberta and it has established a large export industry in the region. The consequent economic development has increased the size and changed the structure of the Alberta economy.

Alberta provides a good case study of what happens to an economy when a potential resource undergoes significant development. There are several reasons for this. The Alberta economy was relatively simple in structure in 1946, largely dependent upon agricultural exports. This reduces the task of identifying and comparing the export industries involved. It was also a more or less static economy whose population had remained stationary for years. This makes possible firm observations on what would have happened to it if the petroleum industry had not entered it on a large

scale. Furthermore, the changes induced by the petroleum industry were so great that an examination of them is worthwhile and rewarding.

What was the sequence of events of the petroleum development in the province? What was the order of their magnitude? What were the population and income effects upon the regional economy? These are the questions with which this book deals. However, before we turn to them it is desirable to provide a background of information about the region and the petroleum industry in it before 1947.

2

Alberta

The Location and Nature of the Province

Alberta is frontier country. It is located in the northwestern part of the settled area of North America, barely half of it populated and the rest an uninhabited wilderness except for some isolated outposts. It became a province of the Canadian federation in 1905 when its agricultural lands were undergoing rapid settlement.

The southeastern two fifths of the province, embracing about 100,000 square miles, contains about one million people of whom one half live in the four cities of Edmonton, Calgary, Lethbridge and Medicine Hat (see fig. 5). This area slopes eastward from an altitude of 4,000 feet at the foothills of the Rocky Mountains to about 2,000 feet at the Saskatchewan border. The surface varies from rolling to hilly and much of it is broken by rivers, draws and coulees. The North and South Saskatchewan rivers are the major streams of the southern settled part of Alberta and both flow eastward into Hudson Bay.

The extreme south, tributary mainly to the city of Calgary, is part of the "dry belt" or prairie region of North America. Here it is relatively easy to carry on oil exploration and drilling activities all the year around because the roads and trails seldom remain impassable for long periods of time because of rain or snow. It was here, too, that the Alberta petroleum industry began exploration and production operations in the early days and that most of these activities were confined until the Leduc discovery.

North and west of the semi-arid south there is a crescent-shaped "park belt" characterized by tall prairie grass, bluffs and patches of woodland. This is Edmonton territory. It gets more rain, has more fertile soil, is more densely populated and has more farms than the prairie south. Here all-

year exploration and drilling operations are hampered considerably during the spring thaws and during rainy spells in the summer when many roads become impassable and the ground generally becomes too soft and muddy for ease of movement by geophysical crews and drilling rigs. The area also remains snow-covered in greater degree during the winter than the southeast.

There is a final incursion of about one hundred thousand people into the Peace River country in the northwest. This extremity of North American settlement is separated from the Edmonton-Calgary region by vast stretches of forest and muskeg (see fig. 5). It is more than 300 miles by rail or highway from Edmonton which serves as its focal distribution and marketing centre. The settlement spills over into the Peace River Block of British Columbia and virtually comes to an end at historical Fort St. John, about 50 miles northwest of Dawson Creek, just west of the Alberta border and located at the end of the 500-mile railway from Edmonton. The Peace River region is similar in nature to the parkland country in the Edmonton crescent and it was mainly farming country before it became explored actively by the petroleum industry during the 1950's.

The rest of Alberta consists of the Rocky Mountains in the southwest and the vast northern continental forest region which occupies most of the western and northern parts of the province. These areas have small agricultural possibilities, but they have scattered pulp, lumber, coal and oil development sites which indicate a great resource potential. The population can be counted by the thousands and it is but a few per cent of the 1,123,000 people found in Alberta by the Canadian census in 1956. Two great rivers wind northward in the forest region, the Athabasca and the Peace. They flow into the Slave River which runs into the Mackenzie River which in turn finds its way to the Arctic Ocean through territory that has an unknown petroleum and other mineral potential. It is difficult country for the oil explorer and driller since he usually has to construct his own trails and roads, and since muskeg and rock often prove formidable obstacles.

Temperatures in Alberta can be extreme and precipitation scanty. Summer days are often hot, while the nights are typically cool. Winter days and nights can be extremely cold and also very mild. The snow fall is meagre by eastern Canadian standards, except in the Rocky Mountains. More than three quarters of the precipitation falls as rain, chiefly during the growing season. If this were not so, Alberta would be a semi-desert and crop cultivation would be out of the question without irrigation. As it is, farming is carried on under precarious conditions for the mean annual precipitation varies from less than 10 inches in parts of the southeast to a little more than 20 inches in the southwest.

Scanty, unreliable rainfall, especially in the southeast, frosts in the

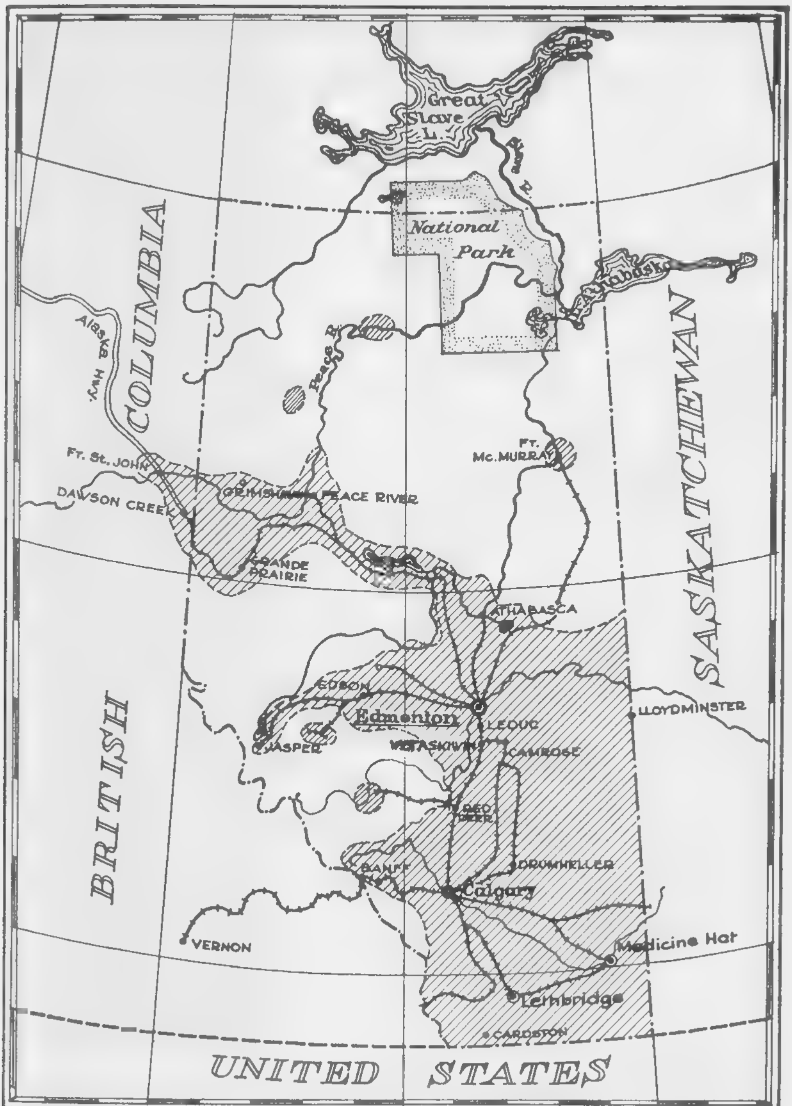


FIG. 5

ALBERTA

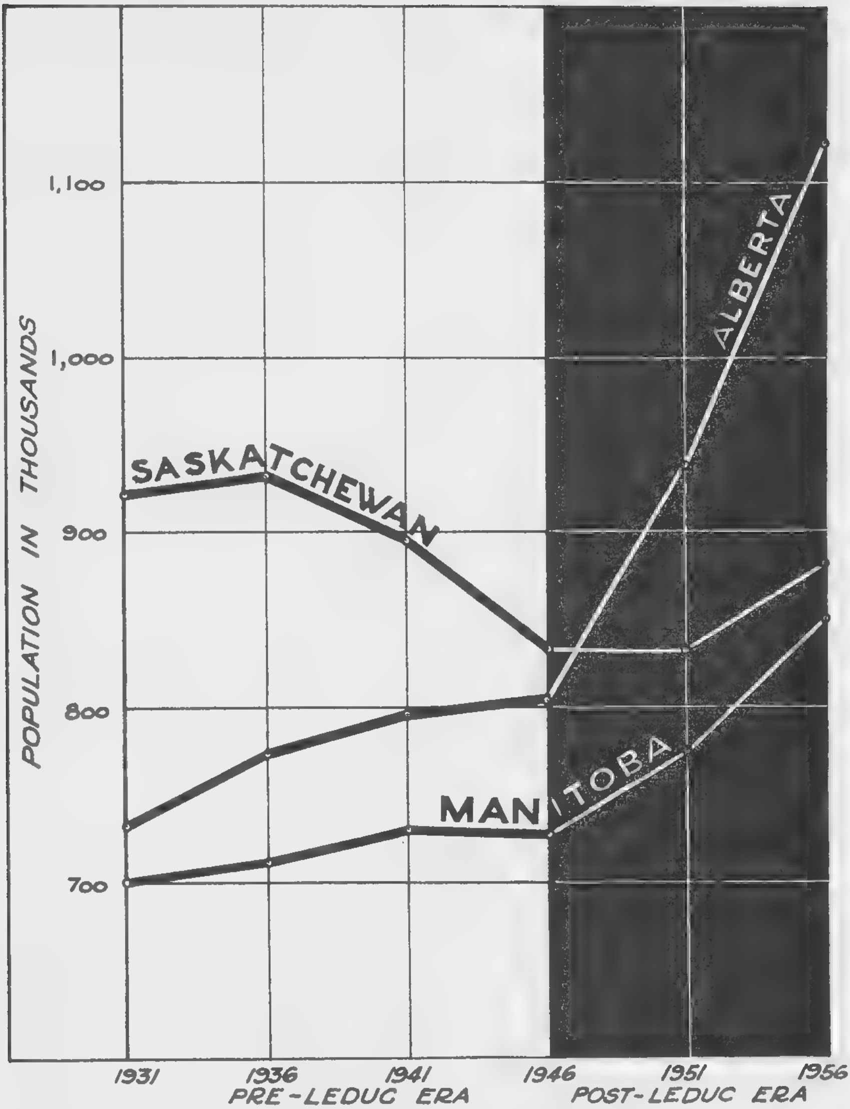


Fig. 6 Population changes in the prairie provinces, 1931-56

northerly parts, and hail storms all make for annual variations in the yields of grain crops. Changes in the demands of agricultural export markets intensify income fluctuations. The petroleum industry and its subsidiary activities, however, are now modifying these fluctuations.

Alberta's Transportation Handicap

Transportation costs have a great effect on the degree to which the resource potential of Alberta is used. Without the railway and the steamship, the main settlement of Alberta which took place during the two decades before the First World War would not have occurred. Its farm lands would have lain idle. Similarly, without pipe-line transportation the Alberta oil and gas potential would be largely untouched and applied mainly to serve a relatively small prairie market.

Before the eighties of the last century, there were only a few thousand fur traders, trappers and subsistence farmers in Alberta. Without the development of the efficient transportation media of the past hundred years there would be practically no Alberta; it would simply have been part of the southern extension of the undeveloped northland of the continent, no matter how large its resource potential might be. Fertile farm lands may produce wheat at a low cost; they have little value if transportation costs to markets are so great as to approach or even exceed the price of farm products in those markets.

In the past, the chief markets for the exports of Alberta were Western Europe and Eastern North America, and these areas were also the major sources of imports. By railroad, the distance from Edmonton to Montreal is about 2,200 miles and it is more than 1,700 miles to Chicago. The Pacific Ocean is much closer than the Atlantic, and Vancouver is only about 700 miles from Edmonton by railroad. However, several mountain ranges must be traversed to reach the western ocean, and transportation through these mountains is costly. Moreover, the Pacific is not an important trading ocean. But the pull of the Pacific coast region is now exerting itself; the Alberta economy is becoming increasingly allied to that of British Columbia as rising crude oil exports go westward and the natural gas potential of the Peace River area is developed.

The Alberta Economy after the Second World War

The prairie provinces sat uneasily on the edge of the world economy in 1946. Their future seemed to depend on securing cost reductions in farm production and on the export demand for farm products. Farm mechanization promised to reduce the number of farms. The export demand for farm products had been unreliable in the past. It seemed that the region could not count upon any substantial economic

progress. There would be a reasonably satisfactory level of per capita income, a decline of the rural population, and a long-run decline of the total population. The large wheat farm, ranch and livestock feeding station would be the typical units of farm production.

Alberta did not get a chance to sit still. Major oil discoveries brought new life to its economy. The petroleum industry expanded rapidly and it attracted other industries to the region. Eventually the petroleum industry spilled over into Saskatchewan, Manitoba and the Peace River Block of British Columbia, again providing impetus to population and income growth.

The change is reflected in the population trends of the prairie provinces after 1946. After a very slight increase in 1941-46, the population of Alberta increased sharply, and in 1946-51 rose from 803,000 to 939,000, a rise of 17 per cent. In 1951-56 the population increased by 20 per cent, bringing the total to 1,123,000, an accretion of 320,000 for the oil decade 1946-56 (see fig. 6). Practically all of this increase can be attributed to the oil development. Before oil was discovered in 1947 at Leduc many Albertans were moving out of the province, particularly to British Columbia and Ontario. Population decline seemed impending to many observers. The discovery of oil checked the outflow of Albertans and stimulated an inflow from other parts of Canada, the United States and even Europe.

The population increase of Alberta after 1946 was of major proportions compared with the increases experienced by Saskatchewan and Manitoba. Fig. 6 speaks for itself. Over the decade 1946-56 Alberta accounted for two thirds of the whole population increase of the three prairie provinces and became one of the major growth regions of Canada.

The People and Places of Alberta

Nearly three fifths of the people of Alberta were born in the province and about three quarters in Canada. About six per cent of the residents were born in the United States. Not quite half of the residents are of British stock; the rest are a cosmopolitan mixture of German, Ukrainian, Scandinavian, French, Polish, Russian and other continental European extraction along with a sprinkling of native Indians and of Chinese and Japanese. They all have two things in common—their location in a relatively remote area and their specialization in two great extractive export industries with province-wide operations. Like most Canadians, Albertans are intensely regional in their outlook and they are keenly interested in all matters pertaining to the welfare of their province.

The capital city, Edmonton, is a busy centre whose 260,000 inhabitants are spread over a metropolitan area of more than 50 square miles, divided

by the deep banks of the North Saskatchewan River. Although it is south of the geographical centre of Alberta, it lies close to the limits of settlement and it is the most northerly major city of North America. More than three quarters of the oil wells of Alberta are located within 100 miles of the city. In the metropolitan area are numerous oil-drilling contractors, oil-well operators and service concerns, oil-industry equipment supply houses, production departments of oil companies, three oil refineries and several petrochemical plants. Natural gas fields abound in the Edmonton region, providing ample supplies of low-cost fuel. Edmonton serves as a wholesaling and marketing centre for more than half the farms and towns of Alberta, including those in the Peace River Block of British Columbia. It has a number of meat-packing plants, dairies and flour mills which export much of their output to points outside the province. A large number of the employees of the Alberta government are concentrated in the city since it is the capital. Edmonton is a military centre of importance. It is also the main educational centre of the province, for the provincial university is located here. Furthermore, it serves as the base from which trappers, miners and adventurers generally make their forays into the vast undeveloped areas of northern Alberta, northeastern British Columbia, the Yukon, Alaska and the Northwest Territories. The city continually looks northward and northern developmental activities are more important in Edmonton than in any other city on the continent.

Nearly two hundred miles to the south and west, located in the foothills of the Rockies and at the junction of the Bow and Elbow rivers, lies Calgary, both rival and partner in the social and economic development of Alberta. Its population of 200,000 is dispersed over an area exceeding 50 square miles. Calgary is the financial and business management centre of the province. Here are most of the provincial head offices of the Canadian chartered banks, Canadian and American oil companies and a host of Canadian and foreign corporations doing business in Alberta. Here is the Alberta office of the Bank of Canada. In addition to serving as the "broker" of Alberta, Calgary performs wholesaling, retailing and marketing services for the farms, ranches and towns of the prairie sections of the province, and it has a variety of manufacturing plants which produce mainly for the regional market. The declining Turner Valley oil and gas field lies some 30 miles to the southwest, but in recent years new oil and gas fields have been discovered in the vicinity of the city. Its proximity to the famous Banff National Park and its widely known annual stampede are factors providing it with a considerable tourist industry. But like Edmonton, Calgary has an economic basis founded on the agricultural and petroleum industries.

In the far south are two sister cities on a much smaller scale than Edmonton and Calgary. They are Lethbridge, about 135 miles south and

east of Calgary by rail, and Medicine Hat, more than 100 miles east of Lethbridge and near the Saskatchewan border. Lethbridge is a city of more than 30,000, serving a number of irrigation districts which produce the usual crops of wheat, oats, barley and grasses, and also sugar beets and a variety of vegetables. The latter provide the basis for sugar refining and vegetable canning industries. A number of small oil fields have been discovered in the Lethbridge area; the large Pincher Creek gas field lies west of the city. Coal mining is an old industry in Lethbridge which dates back to the 1880's, and the city is also the wholesaling centre for the Crowsnest Pass mining area to the west of it in the Rockies.

Medicine Hat has a population of about 22,000. It is the town which Rudyard Kipling described as having "all hell for a basement". Natural gas has made the city what it is; its low-cost gas and its clay deposits led to the establishment of factories which manufacture brick, tile, pipe and flue linings, crockery and tableware. Because of cheap natural gas and the relative mildness of the winter, Medicine Hat has an important greenhouse industry which exports fruits, vegetables and flowers westward into the British Columbia interior and eastward to the Great Lakes during the winter. In addition, the city has flour mills and machine shops and it serves as a wholesaling centre. A large fertilizer plant has been constructed there, using natural gas as raw material and fuel.

There are four more cities beside the ones mentioned. One is Red Deer, halfway between Edmonton and Calgary, with a population approaching 15,000. It has been the distributing centre for one of the oldest and most stable agricultural areas of the province for almost 70 years; the area has broken out with a rash of oil fields since 1950. As a result Red Deer has grown rapidly to serve the petroleum industry. Close to Edmonton are the twin cities of Wetaskiwin and Camrose with more than 5,000 people each and both surrounded by oil fields. About 100 miles northeast of Calgary, situated in the badlands of the Red Deer River, is Drumheller, a noted coal-mining centre with about 2,600 people but also with several oil fields in its vicinity. Finally, the first city in the Peace River area is in process of being created. Here the town of Grande Prairie, which has practically doubled its population during the last five years, largely because of petroleum industry developments, has applied to the provincial government for city status upon its attainment of a population of over 6,000.

There are several hundred towns, villages and hamlets which need not be listed here. A number of them will be mentioned in the course of the story of the petroleum development in the province. Altogether, nearly three fifths of the people live in these centres and in the cities while the rest are located on farms.

3

Alberta's Resources

The province of Alberta, with a population which is currently approaching 1,200,000 and with an area of 255,000 square miles, is a region with a high ratio of land to people. Consequently, the economic progress of the province hinges upon the degree of utilization of its physical resources. Its first great period of economic growth occurred after the turn of the century when much of the agricultural land was occupied. The second major period of growth came after the Second World War when the petroleum resources began to be developed in earnest. In both cases there was a large influx of people and capital accompanied by the application of techniques and innovations devised elsewhere.

Physical resources are only potentials; they have value only if they are wanted and if man knows how to utilize them. As the world is constituted at any given time, with certain conditions of demand for a multitude of products and with the existence of certain methods of production, a physical resource is not an economic resource at all unless its products are among those for which people are willing to pay in the form of prices, fees or taxes, and unless the products can be made at costs which will be covered by the payments of buyers over a reasonable length of time. What matters is the intensity with which the world wants a resource at the time or in the not too distant future. For example, with the rising world demand for petroleum and its products, the value of the petroleum potential of Alberta has become significant in the world, and serious efforts are made to develop it. To tap the potential, the geophysical exploration methods and deep drilling techniques developed during very recent times are being applied. In brief, resources are relative to wants and knowledge, to demand and techniques.

The Agricultural Potential

About one quarter of the land area of Alberta, nearly 45 million acres, is occupied by farms, and of this about one half is under cultivation. If the price of farm products increased sufficiently and appropriate techniques were used, it is possible that the occupied area could be increased by one half. As things stand, Alberta has one quarter of all the occupied farm land in Canada with one fourteenth of its population.

Most of the present occupied farm land was taken up before 1930. Since then the occupied area has risen by only 15 per cent and startling increases are not looked for in the future. The farming industry depends heavily upon export markets which are generally unstable; they cannot be counted upon to expand either rapidly or steadily. Another factor limiting growth of occupied acreage is the lack of undeveloped high-quality land. The soils of the unoccupied potential agricultural lands are mainly of inferior quality and are difficult to utilize economically. Some of the potential farm land is not very accessible and much of the prospective return from such land would be absorbed by transportation costs. Finally, more intensive use of occupied farm land in southern Alberta by the use of irrigation is not expected to be large; the amount of water available for irrigation has limits and irrigation farming has not been a spectacular economic success in the past. Cattle-raising is an important segment of the farming industry which can be expected to expand. The use of Alberta's remaining agricultural potential will depend largely upon the expansion of markets, the adoption of economic techniques for utilizing inferior soils, the extent to which further irrigation is feasible technically, and the degree to which farmers adapt the use of their resources to the output of products for which markets are most favourable.

The Forest Potential

The province has a great potential of forest land which was not used to any marked extent before the Second World War. During the 1940's lumbering grew rapidly in response to the increasing demand for construction materials in the expanding urban centres of the province. Currently (1957), a large pulp mill is under construction at Hinton, 180 miles west of Edmonton. Additional sites for pulp mills are also under consideration. With further economic regional growth arising from the activities of the petroleum industry, the prairie market for lumber

and paper can be expected to expand. Much of the output of pulp will be exported.

The area of forested land covers more than half the province embracing the southwest and the north. Much of this area is inaccessible; at present the stands utilized are located chiefly in the southwestern fringe and at scattered sites in the north. Alberta is currently producing about two per cent of the value of products of woods operations in Canada and about three per cent of the value of lumber and sawmill products. The rate of utilization in physical terms is about one per cent per annum of the estimated forest reserves. This rate will increase as the pulp and paper industry develops. The lumber and pulp industries in Alberta have a future which is closely allied to the over-all development of the petroleum industry and to the availability of low-cost natural gas and sulphur for pulp making.

The Mineral Potential

But it is the mineral fuel potential of Alberta that overshadows that of any other physical resource. Alberta is a veritable treasure house of petroleum, natural gas and coal. These are cheap, convenient and reliable fuels which not only serve to make life comfortable but also can provide a living for the region by being exported. The extent to which this can be done depends primarily upon the extent of the market and the costs of reaching that market, and also upon the degree to which the industries based upon the mineral fuels are located in Alberta. The potential is large and much of it is still unknown.

Coal

Alberta has abundant quantities of coal. It is estimated to have accessible reserves of nearly 50 billion tons, about one half of the Canadian total. This estimate excludes very deep deposits and also those located in areas without transportation facilities. About two thirds of Alberta's accessible reserves are located in the foothill and mountain region. The rest of the accessible reserves is found in the prairie, parkland and the Peace River areas.

The annual rate of production was from seven to nine million tons during the 1940's. During the 1950's there was a decline to annual levels of about five million tons. At this rate it will take ten thousand years to exhaust the accessible reserves. The potential is great, but cannot be realized without markets. Markets for Alberta coal have always been hard

to find. The industrial provinces of Ontario and Quebec are more easily and economically supplied with coal from the fields in the eastern United States. Railway subventions paid by the Canadian government have not been sufficiently large to induce central Canada to purchase large quantities of Alberta coal.

Until the 1950's the railways absorbed about one third of Alberta's coal output. This market has been reduced greatly by the increasing use of heavy fuel oil and diesel fuel by the railways. Cheap and convenient natural gas has been displacing coal for space-heating in Alberta urban centres since the 1920's, a trend which was accelerated during the 1940's when the price of coal, which has a high labour-cost content, began to rise substantially, while the price of natural gas, which has a high fixed-cost content, remained constant or even fell as an increasing number of consumers were served. At present, coal cannot possibly compete with natural gas in the urban centres on the basis of price; the possibility is even more remote when the great convenience of natural gas, Alberta's "invisible servant", is taken into account. Similarly, fuel oil cannot compete with gas in most urban Alberta end-uses of fuel.

Propane, a component of natural gas which can be compressed and stored in tanks, has begun to replace coal as a fuel in small urban centres and on farms during recent years. The neighbouring provinces of British Columbia, Saskatchewan and Manitoba provided one third of the market for coal during the 1940's but there, too, natural gas and propane are taking over.

Here is a great potential resource which will continue largely unused and valueless unless the demand for coal increases or alternative sources of supply shrink. The output of the coal industry will probably not fall much below the present level since there will continue to be a considerable demand for coal by many farm homes and small urban centres on the prairies that cannot be supplied economically by natural gas distribution systems or by propane. There are also power plants in various areas which use low-cost coal from strip mines; this use for coal may, indeed, expand. Special metallurgical grades of coal will also continue to be mined. But the immediate outlook for the coal industry in Alberta, as in so many other places, is not bright.

Petroleum

Petroleum is a hydro-carbon, usually found in a liquid or gaseous state, which consists of a variety of molecules made up of atoms of the two elements of hydrogen and carbon. In its liquid state it is usually referred to as crude oil and in its gaseous state as natural gas.

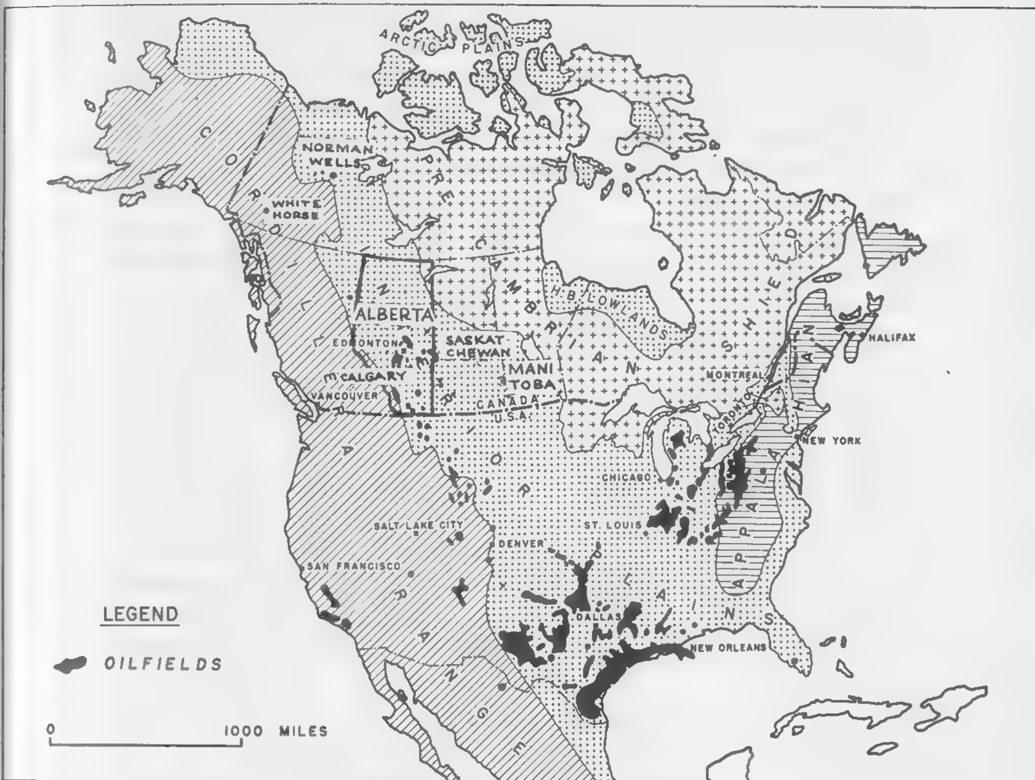


Fig. 7 Main physiographic divisions of North America

Of the two, crude oil has been of paramount importance to date because it is convenient to handle and transport, because it is readily convertible into a variety of greatly desired compounds such as gasoline and fuel oils and lubricants, and because it has a high energy content by volume. Natural gas has been deemed less valuable to date largely because it has a lower energy content by volume than crude oil, it is less economical to transport and it is not easily convertible into other products. However, it is a very important potential source of energy in North America since it has been estimated that the primary energy in the petroleum reservoirs of the continent is approximately evenly divided between crude oil and natural gas. By contrast, there is relatively little natural gas in the Middle East. In North America it is becoming increasingly important as a domestic and industrial fuel and as a raw material for the young and growing petrochemical industry.

A great deal is known about the geological structures and the ages of formation in which petroleum occurs. A number of techniques have been

devised to attempt to find oil underground—geological, geophysical and engineering. The earth's rocks are igneous, sedimentary or metamorphic. Petroleum is found in sedimentary rocks such as porous sands, sandstone, limestone, conglomerate, shale and dolomite; it is only very occasionally found in porous igneous rocks. The search for oil is therefore limited to the sedimentary basins of the earth, about one third of its land surface.

About half of the land area of the United States, a total of about one and a half million square miles, is sedimentary (see fig. 7). In addition, there are the off-shore basins under the Gulf of Mexico. Canada has nearly one million square miles of sedimentary basins, about one quarter of its land area. Approximately four fifths of this, nearly 800,000 square miles, is found in the western Canada basin, embracing the southwest corner of Manitoba, about two thirds of Saskatchewan, nearly all of Alberta, and a wide strip down the Mackenzie River to the Arctic. The Alberta portion exceeds 220,000 square miles. About 500,000 square miles is deemed "favourable", as geologists put it, and this territory of Alberta has more than 200,000 square miles. It has the highest ratio of favourable to sedimentary area in Canada (see fig. 8). To date at least 400 pools of oil and natural gas have been found in Alberta in about 30 geological formations. Alberta, then, has a large petroleum potential.

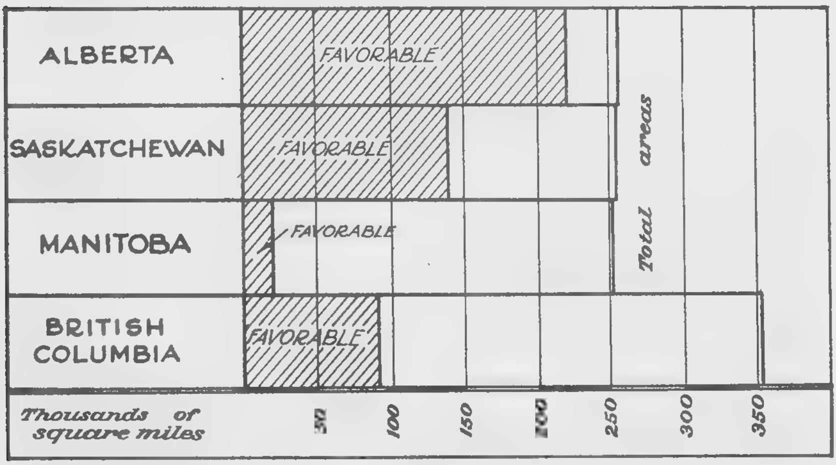


Fig. 8 Total areas of and areas favourable for petroleum exploration in the provinces of Western Canada

What is significant is that the western Canadian sedimentary area is still largely unexplored and undeveloped. A comparison with the United States lends perspective to the prospecting job still to be done in Alberta

and the rest of Western Canada. The United States sedimentary area has been worked over for decades and about one exploratory well per 12 square miles, on the average, has been drilled to date. In the United States intensive exploration and drilling are still going on and promise to do so for a long time; more than 10,000 exploratory wells and over 40,000 development wells are drilled each year. By comparison, about 3,000 wells are currently drilled annually in Western Canada. Only one exploratory well per 150 square miles of sedimentary areas has been drilled in Western Canada and less than one tenth of the area has been explored intensively.

No writer on Alberta resources can ignore the bituminous sand deposits at Fort McMurray, about 300 miles northeast of Edmonton. They have teased promoters and scientists for more than half a century. Local boosters like to point out that they are the greatest known oil reserves in the world. Estimates of the probable content of oil in the sands at present accessible to mining vary from 100 billion to 300 billion barrels; present proven world reserves of crude oil in underground reservoirs are estimated to be in excess of 200 billion barrels. There has been considerable experimental and some operational activity in the area. The Canadian and Alberta governments have both given financial support to projects designed to extract oil from the tar sands. There have been a number of private attempts and currently, with the invention of a centrifugal process for extracting oil from the sands, renewed efforts are being made. There is always someone playing in the sands. To date the results have been of limited economic significance. The discovery of a process which would yield petroleum and its various products out of the heavy crude of the sands, at a cost below those resulting from present exploration and drilling for both light and heavy crudes, could revolutionize the petroleum industry. This would mean that the costs of mining the sands, of separating the oil from them, and of processing would have to be lower than the cost of finding oil in the traditional way. The fact that exploration and drilling activities go on at a high level in Alberta and elsewhere is unequivocal evidence of the present uneconomic nature of tar-sand utilization.

Other Minerals

Alberta has few deposits of non-fuels. There are some salt deposits and the province has been a ranking Canadian producer of salt since 1938. Limestone, sand, gravel, clays and cement are produced in quantity. The province, through Edmonton, serves as a stepping stone in reaching the minerals of the Northwest Territories. Here gold, silver, copper and uranium have been produced in quantity for some

years. Large deposits of base metals are indicated in the Pine Point area south of Great Slave Lake. Finally, significant quantities of oil are produced at Norman Wells in the Northwest Territories.

Other Resource Potentials

The lakes and streams of Alberta contain several varieties of fish. Commercial production is small and equals only about one per cent of the total value of Canadian output. The fur industry was the ranking economic activity of Alberta at one time. It is now unimportant, even though there are vast timbered areas with much wild life. The decline in world fur prices in recent years, largely because of the increasing manufacture of synthetic furs, has lessened the value of the fur resource potential. The annual production seldom runs over five million dollars, usually from one eighth to one sixth of the value of the total Canadian output, and much of it comes from fur farms.

The water-power resources of Alberta are significant, but they are small compared with those of Quebec, Ontario, Manitoba and British Columbia. The best sites are in the foothills region where there are many natural waterfalls and rapids. A serious drawback in power development is the uneven annual flow. In winter the flow in the rivers is but a fraction of the summer flow. Consequently, power from developed sites has to be supplemented by coal or natural gas plants generating electricity to meet peak demands throughout the year. Most of the hydro-electric power in Alberta is generated by one enterprise, the Calgary Power Company. Other companies and municipalities which generate power rely largely upon coal and natural gas.

Hunting and fishing, natural recreation sites and scenery are resources with potential. Alberta offers the tourist many attractions with its forests, foothills and mountains. Three national parks, Banff, Jasper and Waterton, are widely known, and are visited by hundreds of thousands of Albertans and non-residents annually. The tourist industry is therefore an export industry of some importance.

Summary

Alberta has abundant and varied physical resources. It has an invigorating if extreme climate, extensive areas of farm land and forest, large and numerous deposits and reservoirs of mineral fuels, a variety of furs and fish and game, and worthwhile tourist attractions. There are limitations upon the degree of resource utilization. The

relative remoteness of Alberta from world markets and the scattered nature of some of the resources combine to create a high level of transportation costs. Low precipitation and short growing seasons limit the productivity of agricultural land. Demand fluctuations in world markets have aggravated the instability of income. The variable weather conditions, unpredictable from year to year, maintain uncertainty in the farming industry.

Before 1929 the agricultural and coal potentials of the province underwent rapid development and growth in utilization. But for almost two decades after 1929 the Alberta economy was largely static and significant economic progress did not appear to be in the cards after the end of the Second World War. The petroleum industry devised a new deck from the petroleum resource potential of the province. As a result Alberta attracted a great deal of capital. The attendant process of investment generated a rising stream of income in the region, it prevented or modified downturns in the economic activity of Alberta, and it injected a balance into economy which did not exist before.

4

The Petroleum Industry

The search for oil has a fascination for men akin to that for gold and precious metals. When oil is struck in an area there is usually an immediate and almost electric reaction which manifests itself in feverish acquisition of petroleum land rights, drilling activity and real estate booms. Alberta has had more than its share of such experiences since the turn of the century although the oil booms before 1947 were small and fleeting. Oil has to be found in significantly large quantities and in accessible places to create permanent production flows to markets. But before we turn to the Alberta story, let us have a look at the conditions in which petroleum is found and at the different activities of the petroleum industry.

The Occurrence of Petroleum

We have said that the earth's rocks are igneous, sedimentary or metamorphic. Igneous rocks are formed by the cooling and solidifying of hot molten material from the interior of the earth. Sedimentary rocks have been formed by a process of redeposition of existing rocks by the forces of nature such as rain, snow, ice, glaciers, frost and running streams which have been at work for millions of years. When existing igneous or sedimentary rocks are subject to great pressure or heat, they are said to become metamorphic. Nearly all oil and gas pools are found in sedimentary rocks.

It has been estimated that the earth is at least two billion years old and during that period it has undergone continuous structural change right up to the present time. Such change is not perceptible to the ordinary mortal whose life span is but an infinitesimally small increment of time in world history, unless he acquires the tools for doing so by studying geology intensively. Mountains, hills and plains have been eroded, whole

continents have been worn away, oceans and rivers have dried up every few million years, giving way to new surface features, new continents and new oceans. Layers of rock formations have accumulated through time, the more recent on top of the older.

Geologists measure time with several units. The longest is the *era,* a length of time during which marked changes in the physical structure of the earth took place and during which the modified living conditions thus brought about altered the types of animal and plant life on the earth. Usually four such eras are distinguished. The oldest is the Pre-Cambrian which ended about 500 million years ago and which is sometimes divided into two eras, the Proterozoic and Archeozoic. The Paleozoic era lasted for about 300 million years; the Mesozoic followed for another 150 million years, and the Cenozoic has prevailed during the last 50 million years (see fig. 9).

Less pronounced changes in the physical structure of the earth and its life forms took place during shorter intervals of time within eras called *periods*. Studies of the sediments deposited during the most recent periods have provided information which has enabled geologists to distinguish shorter intervals of time again than periods, called *epochs*. Fig. 9 is a summary geologic time table, indicating the names of eras, periods and epochs.

The remains of animals or plants (fossils) or their impressions, preserved in sedimentary rocks, provide most of the information for tracing the evolution of life and the structure of the earth. It seems to be most generally thought that oil and gas are substances which have evolved from decayed animals and most particularly from marine life. The bodies of these animals came to rest at the bottoms of oceans where they became embedded in vegetable matter and silts brought to the sea by rivers. As the oceans dried up and new ones were formed, much of this organic matter escaped at whatever surface the earth currently possessed geologically; the rest was imprisoned by buckling, folding, tilting and overturning of the various layers of sedimentary beds. The varying pressures of formations together with the presence of differing chemical elements have given rise to many differences in the qualities and compounds of gases and oils.

Oil and gas are found in traps caused by folding and faulting or by changes in the permeability of rock strata. There is a great variety of these traps and their classification is an intricate matter, even for the specialist. It is this very variety which makes it impossible to rule out any given sedimentary area as entirely devoid of oil. Some of the names which are commonly used to label these traps are anticlines, synclines, monoclines, domes, reefs, crevices, faults and unconformities. These geological structures are shown in fig. 10. Some of them, for example the

Fig. 9. Summary Geologic Time Table

Era	Period	Epoch	Time Since Beginning of Epoch or Period millions of years
Cenozoic	Quaternary	Recent	
		Pleistocene	1.7
	Tertiary	Pliocene	15
		Miocene	33
		Oligocene	42
		Eocene and Paleocene	53
Mesozoic	Upper Cretaceous		
	Lower Cretaceous		108
	Jurassic		135
	Triassic		158
Paleozoic	Carboniferous	Permian	191
		Pennsylvanian	232
		Mississippian	265
	Devonian		304
	Silurian		326
	Ordovician		383
	Cambrian		475
Pre-Cambrian			
I PROTEROZOIC	Keweenawan		
	Huronian		
II ARCHEOZOIC	Timiskamian		
oldest	Keewatin		

Sources: Engineering Committee, Interstate Oil Compact Commission, *Oil and Gas Production*, University of Oklahoma Press, Norman, Oklahoma, 1951, p. 8 and *Encyclopedia Americana*, "Geology".

anticline, may provide telltale surface signs through upthrusts, depressions and outcrops with significant meaning for trained geologists. Others, such as the reefs, give practically no indication at the surface of their existence, and hence the discovery of reef traps, such as those of the Leduc and Redwater fields in Alberta, was mainly a matter of chance until geophysical methods of exploration were developed.

The rock above trapped oil and gas is impervious and prevents them from escaping. Contrary to a common misconception, the oil in a trap is not a lake which occupies the space concerned exclusively. It is found

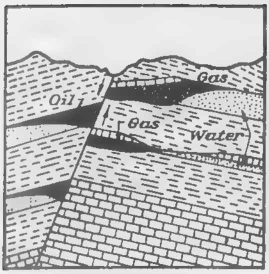


FIG. A.

CROSS SECTION SHOWING DISPLACEMENT OF ROCK LAYERS ALONG A FRACTURE. OIL AND GAS TRAPS MAY OCCUR ON BOTH SIDES OF THE FAULT. (AFTER LeRoy)

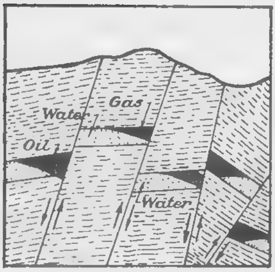


FIG. B.

NUMEROUS FAULTS WITH OIL TRAPS IN EACH FAULT BLOCK. THE FAULTS MAY EXTEND HORIZONTALLY FOR MILES. (AFTER LeRoy)

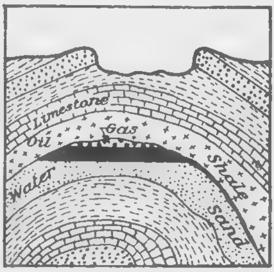


FIG. C.

ANTICLINE OR DOME WITH TRAP FOR OIL AND GAS. ANTICLINES ARE ELONGATED DOMES.

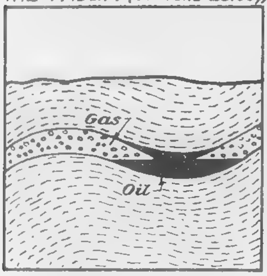


FIG. D.

A SYNCLINE WITH OIL AND GAS TRAP.

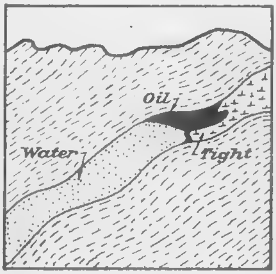


FIG. E.

A MONOCLINE. THE UPPER BOUNDARY OF THE OIL TRAP IS TIGHT ROCK. (AFTER LeRoy)

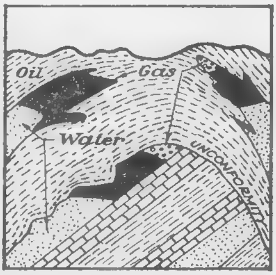


FIG. F.

OIL TRAPS ABOVE AND BELOW AN UNCONFORMITY AND BURIED RIDGE.

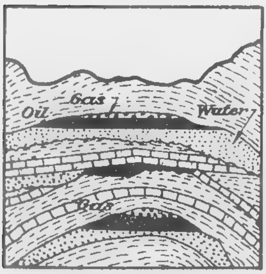


FIG. G.

ANOTHER EXAMPLE OF OIL TRAPS ABOVE AND BELOW AN UNCONFORMITY (AFTER LeRoy)

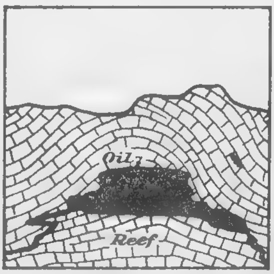


FIG. H.

LIMESTONE REEF TRAP.

FIG. I.

OIL IN CREVICES AND SOLUTION CAVITIES OF LIMESTONE.

Fig. 10 Geological structures of oil traps

Adapted from Engineering Committee, Interstate Oil Compact Commission, *Oil and Gas Production*, pp. 11-13.

in porous sands, conglomerates, limestones, sandstones and shales. When these sands or porous rocks are penetrated by drilling through the impervious rock above a trap or pool, the oil migrates laterally toward the hole through the pores and then pushes upward similarly, driven by the pressure of free gas lying on top of the oil or by gas dissolved in the oil or by water under the oil or by any two or all three of these drives. Free natural gas, which is lighter than oil, occupies the pores above the oil, and free water, which is heavier than oil, fills the pores beneath it. In short, a pool of oil or gas or both is like a sponge which is soaked in oil and water and is then imprisoned in a tight box. If left long enough, some gas in the oil rises to the top and most of the water goes to the bottom. If a hole is punched in the box at the top and a tube is inserted, gas, oil and water will spout forth.

Actually, the "sponges" of rock in which oil and gas are found are very solid, just as much so as the limestone or sandstone used to construct a building. The pressures of the gas and the underlying water drive oil, gas and water through the tiny pores. *Porosity* is a term used to describe the amount of pore space in the sand or other reservoir rock which determines the amount of oil, gas or water which the rock can hold. The grains in oil-bearing formations may vary in size from less than $\frac{1}{250}$ of an inch to $\frac{1}{50}$ of an inch in diameter. In estimating the amount of oil in a trap, porosity is a major factor to be taken into account, and one of the difficulties in measurement is that it is by no means uniform in a pool. The oil saturation of a rock also has to be considered, for some "connate" water usually adheres to the rock grains and thus occupies the porous spaces along with the oil in the oil layer of the pool. Another factor affecting the recovery of oil is *permeability*, the ability of a fluid to flow through the pores; the grains of sand are not necessarily uniform and they differ in degrees of interconnection. Low porosity, saturation and permeability make it difficult to obtain oil from a trap or pool.

The underground layer of porous rock in which oil, gas and water have been trapped and from which oil or gas or both are produced is commonly termed the *producing horizon* or *zone*. In describing such a unit it is customary to refer to its geologic period, the depth of drilling required to reach it and the average thickness of the *pay zone*. Often the formation may be a variation of the general type and carry a local name or the name of a place where oil or gas was first found in the peculiar variation of the formation to which it belongs. For example, one producing zone of the Leduc-Woodbend field in Alberta is Devonian in age, and it is named Nisku (D-2) carbonate (dolomite) after the railway siding of Nisku six miles north of Leduc. Its approximate depth is 5,050 feet and the average thickness of the pay zone is 30 feet. The producing zone of the Joarcam field southeast of Edmonton is Lower Cretaceous in age,

and it consists of Viking sandstone, so named because it is similar to the sandstone formations in which gas was found before the First World War at Viking, Alberta. Its approximate depth is 3,300 feet and the average pay zone nine feet in thickness.

A productive formation may contain several pools of petroleum. A *pool* of petroleum is closed off from others by impermeable rocks, water, faults, changes in porosity and permeability, pinching-out of reservoir beds or synclinal conditions. A *field* may consist of only one pool or many. The pools in a field, too, may overlie each other in different productive formations or zones. For example, the Leduc-Woodbend field consists of pools trapped in four productive zones at depths averaging 4,200 feet and 4,300 feet for two Lower Cretaceous zones and 5,050 feet and 5,350 feet for two Devonian zones.

Oil and gas pools are found in rocks ranging in age from Pre-Cambrian to Quaternary. Very little oil has been produced from Pre-Cambrian rocks because they were formed at a time when there was practically no animal and plant life on the earth. Whatever oil is found in these rocks is believed to have migrated from younger formations lying on top of them. The Pre-Cambrian rocks are usually igneous or metamorphic with very little porosity and permeability.

Paleozoic formations (see fig. 9) have produced about one third of the world's oil. There is a great variation in the oil-bearing qualities of the rocks of different periods because of differences in the nature and abundance of plant and animal life that existed when the sediments were deposited during each period. Rocks of the Pennsylvanian epoch have been the most prolific of the Paleozoic era, followed by the Permian, Mississippian and Ordovician. The Permian Basin of western Texas and southeastern New Mexico is a famous oil-producer. Mississippian formations are distributed throughout the United States and the deep producing zone of the Turner Valley field in Alberta found after the First World War is limestone of Mississippian age. Ordovician formations are particularly characteristic in Oklahoma and the Pennsylvanian throughout the sedimentary areas of the United States east of the Rockies. Rocks of Devonian age have been less productive than those mentioned previously and have produced about one fiftieth of the world's oil, but they are particularly important in Alberta where they contain more than 60 per cent of the present known recoverable reserves of the province. The Cambrian and Silurian rocks have been relatively unimportant producers to date.

Rocks of the Mesozoic era have produced about one sixth of the world's oil, of which those of the Cretaceous period account for more than 90 per cent. Productive Cretaceous formations abound in Alberta and contain more than one third of the present estimated recoverable

reserves of crude oil in the province and about half of the disposable reserves of natural gas. Rocks of the Triassic and Jurassic periods have produced less than one per cent of the world's oil. Some productive formations of Jurassic and Triassic age have been discovered in Alberta.

Rocks of the Tertiary era have provided more than one half of the world's oil to date from formations in the United States, South America, Europe, the Middle East and other parts of the world. The Tertiary formations, however, are missing throughout most of Alberta and the few that were explored have so far failed to yield commercial quantities of gas and oil. The story of Alberta oil is centred largely around Cretaceous, Mississippian and Devonian formations, deposited from 50 to 300 million years ago. For the world as a whole, the age range of productive oil and gas formations is from about 10 to 450 million years, and more than two thirds of the crude oil produced to date has come from formations less than 100 million years of age. As the trend toward deeper drilling continues in the United States and the Paleozoic formations of Western Canada are explored by the driller, the older rocks of the earth can be expected to contribute a larger proportion of the oil produced in North America in the future. Middle East productive formations are mainly Tertiary and Upper Mesozoic (Cretaceous) and this will keep the "young" rocks very much in the over-all world picture.

The Risks of Petroleum Exploration

The science of petroleum exploration has come far since Drake drilled his famous Titusville, Pennsylvania, well. He struck oil at about 70 feet and it is said that for years drillers abandoned operations as soon as they reached this depth without finding oil. Until the end of the nineteenth century surface seepages of oil, doodle bugs, divining rods or plain hunches were relied upon to select the spots for drilling. Considerable oil was found in this way because, after all, no one had tried to tap any production zones before. The continued universal use of such methods, however, would have required an enormous amount of drilling to discover the produced and unproduced reserves found to date.

Many oil producers realized the high probability of error in hit-and-miss methods, and by the turn of the century they began to turn increasingly for help to the developing science of geology. A corps of geological consultants appeared in force by the 1920's, and the large companies began to hire their own full-time geologists. These geologists were not infallible but proved their worth in the long run. Geophysical methods

have been developed in recent decades to follow up geological reconnaissance.

The search for oil has gone on in Western Canada since the end of the nineteenth century. Two substantial fields, Turner Valley and Norman Wells, and a number of small pools were found before 1947. Some geologists, notably Dr. T. A. Link, spent much time in studying the region as a potential oil-producing area. In an address to the American Association of Petroleum Geologists in late 1945 Dr. Link outlined the potential petroleum area of Western Canada and envisaged future discoveries in it. Behind such men there were enough serious operators to keep the search going. Companies like Imperial, followed by international majors such as Shell, Gulf and California Standard and a sprinkling of Canadian independents such as Home Oil, Anglo-Canadian, now Canadian Oil Companies, and the Calgary and Edmonton Corporation, were spending millions of dollars on exploration of the prairies in 1946. It took the accumulating knowledge of three decades of exploration to achieve the breakthrough of the last decade, and Western Canada is far from fully explored even yet. The following table is indicative of the success and volume of exploratory drilling done in Alberta before and after 1947.

Number of Exploration Wells
Drilled in Alberta to the end of 1956

	Found Oil	Found Gas	Failures	Total	Failures as Per Cent of Total
Prior to 1927	2	24	108	134	80
Prior to 1937	8	29	199	236	84
Prior to 1947	27	48	492	567	87
Prior to 1957	582	548	2,839	3,969	71

Source: Floyd K. Beach, western editor, *Canadian Oil and Gas Industries.*

It is obvious that the amount of exploratory drilling done in Alberta before 1947 was small relative to the amount done during the last decade. The failure ratio, too, was very high before 1947; seven out of eight exploratory wells drilled in the province before 1947 found neither oil nor gas, and only one well out of twenty drilled found oil. The failure ratio fell after 1946 but it is still inevitably high for oil is difficult to find.

The following excerpt from the *Imperial Oil Review* of June, 1946, is indicative of the hopes of the industry for the prairies as a potential oil-producing region before the era of current development:

"This may come as a surprise to some but man's knowledge of what lies beneath the surface of the earth is gained slowly. Oil is found in areas

where sedimentary deposits were laid down in ancient seas. Such deposits lie in varying thicknesses from the Rockies far across the prairies, and from the prairie U.S. border to the Arctic. In the Rockies they run to a depth of 10 miles or more and, generally speaking, taper off to more shallow depths eastward. In spite of aerial photography, the study of outcroppings of rock and of subsurface contours, examination of surface seepages and other geological data in this vast area, it is still necessary to drill, for only by drilling do we get a final test, which may or may not confirm the geologist's hopes. However, from a careful examination of cuttings obtained by drilling, first at one location and then at another, it is becoming possible to piece together a pattern of the subsurface geology which may lead to the discovery of oil. It is a rather remarkable fact that, of approximately 1,600 holes drilled in Western Canada to date, less than a dozen can definitely be accepted as having been drilled deep enough to test all the possibilities of the sedimentary deposits. We need not, therefore, be discouraged if there appear to have been relatively few tangible results from western exploration up to the present time."

Western Canada was largely untested territory before 1947. Only about 600 exploratory wells had been drilled, not even one per 1,000 square miles. About 1,000 development wells have been drilled in proven and semi-proven areas; they provided largely localized knowledge of formations. What was needed was to drill deeply enough and often enough, for there is no sure test of the existence of oil but to drill.

Drilling is generally costly. For example, Imperial drilled a dry hole at Coalspur in the Alberta foothills before 1946 to a depth of 12,955 feet at a cost of $800,000. During 1944 and 1945, Imperial and Shell joined to spend one million dollars on exploration and drilling of a well at Stolberg, also in the foothills. It was an unsuccessful venture and drilling was abandoned at 13,747 feet. In the fall of 1946, Gulf, Imperial, McColl-Frontenac, Shell and Socony-Vacuum set up a joint enterprise called "Operation Muskeg" which involved drilling a well in the foothills just outside Jasper Park, 200 miles west of Edmonton. Drilling began in early 1947 and continued until late in 1948 when the well was abandoned after a depth of 10,709 feet had been reached without any discovery of oil. The venture cost the partners $1,600,000 for exploration and drilling and for the construction of a road to the site. It would probably have been necessary to drill at least a dozen wells in each of these foothills locations to prove fairly definitely if there were oil in them. This would have been a most expensive undertaking. The typical well in the plains region costs about $100,000 to drill and complete; in shallow formations it may be considerably less than this.

Drilling in the foothills was encouraged because the Turner Valley field lies in these. In this field drilling depths varied from 7,000 to 9,000 feet and the minimum cost of drilling a well in 1946 was $150,000. Many of the producing wells in the field will never yield enough to pay for the cost of drilling. Other wells may provide very handsome returns, sometimes many times the cost of drilling.

There is often doubt that ultimate production from a field will meet the cost of exploration, drilling and well operation. Nor can the industry be certain that the total expenditures in a whole region like Alberta will be recovered through the revenues from successful wells. Individual companies and operators who drill for oil can only hope that their particular search will be successful.

To date the rewards of successful searching for oil have been frequent and large enough to induce oil companies and individuals to keep on exploring the subsurface of sedimentary basins. They know that they have to take whatever price they can get for any oil found, regardless of the costs incurred. In the long run, however, exploratory and drilling costs have to be weighed against prospective prices. During the forties in Alberta, the oil explorers turned away increasingly from the deep, difficult and expensive drilling required in the foothills, both in the Turner Valley field and in strictly wildcat territory. It is true that the plains area had yielded only small amounts of usually heavy, pitch-like oil. But the Princess field indicated the presence of formations of Devonian age with light oil under the plains of southern Alberta. More important, the seismographs which Imperial began to use increasingly after 1940 were hearing some "heart murmurs" in the Edmonton area which had previously been practically overlooked by wildcat drillers. As a result of patient exploration and the application of steadily improving exploratory techniques, large oil fields were discovered in the area.

The Activities of the Petroleum Industry

There is a continuous and rising demand in the world for petroleum and its products. To meet this demand the petroleum industry engages in a variety of activities which are attended by various degrees of risk.

The first step in the production of oil and gas is to search for them. This activity is usually called exploration and it is full of both nature-made and man-made uncertainties. It involves the choice of petroleum-prospective locations, the acquisition of land rights, the employment of geological and geophysical crews to search areas mapped out, and the engagement of drillers to apply the ultimate test in the locations finally selected. The

activities of exploration have been likened to a game of poker in which nature provides the cards and men the competition. The cards in themselves provide only imperfect information; a player does not know for sure what information the others have and so considerable bluffing is attempted with a greater or smaller degree of success. It is easy to play until your money is gone, but it is not so easy to win a large jackpot.

It is customary for oil companies to obtain the services of geophysical contractors, geological and geophysical consultants and drilling contractors to carry out their directions to explore specific areas and to drill wildcat wells in them, but large companies may have their own geologists, geophysicists and drillers. Exploration is often the most fruitless of activities which demands all the skills and knowledge of its practitioners. Geologists are in a peculiar position. If they are too cautious, they may have a high batting average but few discoveries to their credit for they seldom decide to go to bat. If they are too eager to do so, to recommend drilling in every likely spot, they will have a low batting average; but they might just find one or two of those one-hundred-million-barrel fields (or greater) about which oilmen dream. If they do it is like driving in the winning run in the final and deciding game of the World Series, a feat which is occasionally accomplished by players who have not distinguished themselves during the regular season.

The funds of any company are limited relatively to the amount of exploration work that could be done, and the returns from indiscriminate drilling will nearly always be insufficient to meet exploration costs. Yet chances must be taken, and they are assumed by oil companies, both large and small. The large are usually primarily concerned with obtaining a reliable supply of oil through the years to ensure continuity and independence of all their operations; they play the game, not only with the view of maximizing profits but also with that of trying to ensure that they will retain or expand their share of the market or their status in the industry. This often means that they will pass over petroleum-prospective areas whose acquisition and exploration might be so costly as to endanger their long-run financial position, or more likely, be less attractive and more speculative than other properties. Here the small companies, whose activities are confined mainly to land acquisition and production, have a chance to secure large prizes occasionally provided by successful finds. Often, however, they have to go home from the oil-poker game, more or less stripped of their possessions. But in the process, these so-called "independents" find a great deal of oil—indeed, to date they have discovered more oil in the United States than the large integrated companies. Hence the independent oil producer is an essential part of the industry.

Once oil or natural gas or both have been discovered in an area by the token of successful wildcat wells, a program of development is under-

taken if market prospects look favourable in relation to costs. Development involves the drilling of wells to tap the oil in a field economically and efficiently and to demarcate its boundaries. This may take years if the field is a major discovery or it may be only a matter of weeks if the discovery proves to be very minor. The company making the discovery may be small or large; if it has large acreage holdings in the area it may decide to "farm out" some of it, an arrangement whereby mineral rights are assigned by one party to a second for development and, of course, for a consideration which usually is a stipulated share of the production of any oil wells brought in. Large companies may farm out holdings to others because their funds may be committed elsewhere to a point at which they will not have enough to develop all the acreage in the discovery area alone; furthermore, the farming-out process spreads the risks involved in development, for drilling on every parcel of land in the vicinity of discovery wells is not a sure-fire proposition. Usually, it is the less favourable acreage of a company which is farmed out, and unfortunately many of the companies taking these farmouts are small and are often unable to hedge the risk of drilling on farmouts by acquiring and drilling on more favourable acreage. Again many companies may have had acreages in the area before the discovery and they may farm out parcels of these. Thus many companies, large and small, may participate in the development of a field.

The next step is production of oil and natural gas from successful wells. This activity calls for engineering skills of a high order for a number of interrelated factors affect the rate at which oil or natural gas can be extracted optimally. It may call for regulation of the underground pressures which drive oil and gas upward, for pumping the oil from the underground depths, or for injections of water or gas or chemicals to facilitate the flow of oil and to increase the ultimate amount recovered. Well-operating contract services are usually obtained by companies which are not large enough to engage full-time petroleum engineers and technicians; they may also be utilized by large companies, especially when the problems of production in a field are of such a nature as to demand highly specialized servicing.

Storage becomes necessary after oil has been extracted from the ground, and an oil field becomes dotted with many tanks for the collection of oil from the producing wells. These tanks enable operators to measure well output and to store oil until it is transported to refineries or to centralized groups of large tanks awaiting delivery to pipe lines, and at pipe-line and water-transportation terminals.

Transportation is an important part of the petroleum industry. Tank trucks may be used to haul crude from wells whose level of output precludes the economical construction of a railway or a pipe line. They are also used extensively to transport petroleum products from bulk stations

to service stations and other purchasers. There are the railway tank cars which may be used to transport crude oil from wells or fields whose production is insufficient to justify the construction of a pipe line; they are also used to transport manufactured petroleum products. There are the pipe lines, trunk and gathering, which, in contrast to tank trucks and railway tank cars, are usually owned and operated by oil and gas companies. Gathering systems transport oil from field tanks to tank farms and from the latter the oil may move out by truck, railway or by pipe line to refineries. The largest pipe lines, which may serve a number of refineries and which may be national or continental in scope, are called trunk pipe lines. Some pipe lines carry manufactured products. Finally, there are many oil companies which carry crude oil and its products over the navigable water bodies of the earth to refining or marketing centres. The bulk of all crude oil is transported by pipe lines and by tankers.

Another phase of the industry is manufacturing, or in common parlance, refining. This activity involves the conversion of crude oil into literally hundreds of products. Refineries process crude oil and absorption plants natural gas. In recent years, the petrochemical industry has become important; it manufactures plastics, fibres and chemicals from refinery by-products and natural gas. Manufacturing is a part of the activities of integrated companies but some small companies specialize in this operation.

The final step of petroleum industry activities is marketing. Bulk plants distribute the products of oil refineries to regional service stations, other local users and to customers outside the region for export. Natural gas absorption plants sell their output to gas distribution systems (which may have their own absorption plants), to chemical plants or to other customers.

The functions of the petroleum industry have traditionally been assumed by private enterprise in the United States, the original home of the world oil industry. Governments in the United States and Canada have gradually tempered the actions of operators in the industry by various regulations, including those pertaining to restraint of trade, conservation and prorating of production. In the United States there are thousands of firms, large and small, performing one or more of the functions of the industry. According to a survey of the American Petroleum Institute there were more than 42,000 companies in the United States in 1949 engaged in the various phases of the oil industry from exploration to wholesale product distribution. In addition, there were about 180,000 service stations and other retail dealers in petroleum products.

The large integrated "majors" engage in every phase of industry activity and the names of Standard Oil of New Jersey, Shell, Texas Company, Gulf Oil, Socony-Mobil Oil, Standard Oil of California, Pan-American Petroleum Corporation (formerly Stanolind), Sinclair, Phillips and Cities

Service, the ten largest oil companies in the United States, are household words. Most of these companies have also extended their activities to Canada, South America, Europe, the Middle East and the Far East, either by direct investment or through affiliates or subsidiaries. In these ventures they have been joined by such Western European giants as Royal Dutch Shell and the British Petroleum Company. Canada, because of its proximity to the United States, has attracted a sizeable group of "minor" integrated or large independent producing companies such as Amerada, Amurex, Atlantic, Cleary, Fargo, Husky, Ohio, Seaboard, Sun, Southern Production, Tennessee Gas and Union Oil of California. The Continental Oil Company of the United States works in association with the Hudson's Bay Oil and Gas Company, a Canadian company with land holdings throughout Western Canada.

The petroleum industry is without question venturesome and variegated in its activities. It is international in scope and many oil men could qualify as "world citizens" on the basis of their experience and outlook. The oil business is as hard-headed as any business but it is also colourful and visionary. The early history of the petroleum industry in Alberta is illustrative of this observation, and to this story we shall now turn.

5

Early Discoveries

The Early Search for Oil in Alberta

The early history of the search for oil in Alberta is largely one of disappointments and losses of investments, but there were enough discoveries to induce someone to keep on searching for the elusive underground pools in which oil is characteristically found. Early exploration techniques were usually not scientific and drilling methods were crude and inadequate for reaching deep formations.

The first discovery of oil in Alberta seems to have been made in 1788 by Peter Pond, a northern explorer, who reported on the oil seepages from the sands along the Athabasca River in the Fort McMurray area, some 300 miles northeast of Edmonton. Five years later his report was confirmed by Sir Alexander Mackenzie. The first detailed investigation of the mysterious sands was undertaken in 1878 by George Dawson, Director of the Dominion Government Geological Survey. Since then millions of dollars have been spent by governments and exploration companies to develop the sands technically and commercially. To date no method has been devised for extracting petroleum and its products from the bituminous sands which costs less than it does to discover petroleum in the conventional manner. Fresh attacks upon the sands are being made currently by the Royalite Company and associates.

So much for the famous tar sands, potential oil producer when traditional methods of looking for petroleum become so costly as to make their exploitation economical. There were few attempts at drilling for oil until the turn of the twentieth century. The first discovery of note was that of natural gas in 1883 at Langevin, now known as Alderson, about 40 miles northwest of Medicine Hat. The gas was found at a depth of about 1,000 feet in the course of attempts by the Canadian Pacific Railway to obtain a water supply for a railway water tank. Several wells were drilled

to similar depths; they produced a little gas but practically no water. The gas was not used commercially.

In 1890 the first commercial gas well was drilled at Medicine Hat in the course of searching for coal. However, it was not until 1904 that the Medicine Hat gas field came to be utilized in earnest. After that date the City of Medicine Hat drilled a number of wells to supply the city with fuel for heating and industrial uses. Gas lights were installed on street corners in the centre of the city and along the railway station platform. These lights were left burning day and night for this was less expensive than hiring someone to turn them on and off daily. It seems that it was these gas lights which prompted Rudyard Kipling to make his infernal remark about the city when he visited there before the First World War. Before that war Medicine Hat attracted a number of manufacturing plants which were heavy fuel-users, and to these we have already referred.

In 1912 some real estate promoters laid out a townsite, about six miles northwest of Medicine Hat, and called it Redcliff. They advertised widely to attract industries, promising practically free natural gas. Several brick plants and a glass plant were constructed. Even a steel-rolling mill was set up as well as a number of small establishments which tried to produce such articles as textiles and shoes. A present resident of the town declares that there is still a box of shoes extant which were made in Redcliff before the First World War. Someone dubbed the Medicine Hat area the "Pittsburgh of Western Canada". A severe windstorm blew away most of the initial flimsy structures of exposed Redcliff one day while those of Medicine Hat, located in the shelter of the river valley, were spared. Little effort was made to rebuild the town as the war came along and the declining population was left to cope with a large municipal debt. However, the town was hardy and has grown again; today there are about 2,000 people in Redcliff. The Dominion Glass Company plant kept operating through the decades and is now serving a growing western Canadian market, selling many kinds of commercial glass containers such as canning jars and soft drink and beer bottles. Two brick plants are also in operation.

Induced by the existence of the Fort McMurray tar sands, the Geological Survey Division of the Dominion Government undertook to drill for oil at Athabasca Landing, 100 miles north of Edmonton, in 1894-96, and at Pelican Rapids, northeast of the Landing in 1897. Some gas was found at Athabasca Landing where drilling to nearly 1,800 feet was done before abandonment. At Pelican Rapids gas was struck at about 800 feet and was left to flow uncontrolled for more than 20 years when the Dominion government at last dispatched a party headed by A. W. Dingman, a prominent driller, to the site to turn it off. Drilling activities were transferred to Victoria, nearly 100 miles northeast of Edmonton along the North Saskatchewan River, in 1897-99. Here no indications of either

gas or oil were found; drilling went on laboriously to nearly 2,000 feet as the drillers "ran out of hole" in the sense that the hole became so small from the use of successively smaller casing that they could go no farther.

Down in Waterton in the extreme southwestern corner of Alberta, oil seepages on Cameron Brook (also known as Oil Creek) attracted the attention of John George (Kootenai) Brown who collected some crude in 1886 and used it for greasing machinery on his ranch. One of Brown's employees, William Aldridge, is later said to have hit upon the idea of digging trenches and pits into which oil seeped and then of selling it to district ranchers at a dollar a gallon. A popular use of Waterton oil was as cattle dip to cure mange.

In 1902 A. P. Patrick, a Dominion government land surveyor, and John Lineham of Okotoks began drilling operations at Waterton under the name of the Rocky Mountain Development Company. They struck oil at a depth of 1,020 feet and the flow is said to have been at the rate of 300 barrels per day. Unfortunately the drilling tools became stuck in the hole. Pumping was resorted to and several thousand barrels of oil were brought up, making total production of the well about 8,000 barrels. Lineham and Patrick marked out 50-foot lots in the neighbourhood, registered them at Ottawa and called the place Oil City. Speculators and drillers were attracted to it but the boom was short-lived. The obstacles were too great. The roads and trails were far too rugged to permit transportation of heavy machinery, and once the oil was extracted, it had to be packed out by mules at prohibitive costs. The closest refining facilities were at Vancouver and Sarnia and only the crudest of refining was attempted on the site. Altogether it seems that only about 20 barrels were used. Furthermore, a number of wells drilled in the area to depths of 1,500 to 2,000 feet failed to yield any oil. It appears that the little bit of oil found had migrated from some other formation. By 1907 the area was abandoned for oil-drilling purposes although one unsuccessful attempt was again made in the 1930's. Some wells were also drilled in the Pincher Creek region, north of Waterton, during the 1920's without success.

A search for natural gas was initiated in Calgary in 1905 when A. W. Dingman incorporated the Calgary Natural Gas Company and sold stock mainly to Calgarians. At about the same time the Calgary Gas Company was organized, and it constructed a plant that manufactured artificial gas. It laid about 25 miles of mains and served almost 2,000 customers by 1910. The Dingman company drilled two unsuccessful holes, one on the Sarcee Indian Reserve in 1906-08 to the remarkable depth of 3,400 feet and another in East Calgary in 1908 to a depth of 3,125 feet. A little gas was found in the latter.

In 1910 the two companies were amalgamated with a new developmental company named The Prairie Fuel Gas Company, which was re-

organized in 1911 as The Canadian Western Natural Gas, Light, Heat and Power Company. The new organization held the franchise to distribute gas in Calgary and acquired franchises in Lethbridge and towns between it and Calgary. The Canadian Pacific Railway had found some natural gas at Bow Island, Brooks and Bassano. The new company acquired interests in these areas and began a drilling program concentrated in the Bow Island area between Lethbridge and Medicine Hat. A number of wells were brought into production between 1912 and 1920, but the quantities produced were insufficient to provide customers with an assured, regular supply. Some gas was found at Foremost, south of Bow Island, but the quantities were insufficient to solve the company's supply problems. It took the discoveries at Turner Valley, 30 miles southwest of Calgary, to provide reasonably adequate amounts of natural gas for Calgary, Lethbridge and intervening towns.

The Turner Valley Oil and Gas Field

William Stewart Herron was a rancher at Okotoks, 20 miles south of Calgary. Of winters he contracted to haul coal from the Black Diamond mine in the Turner Valley to the power plant at Okotoks. On one of these trips he noticed gas seeps near Sheep Creek. It is said that he up-ended a big barrel over a gas fissure and collected samples which he sent to the University of California for analysis. The reply came back to the effect that it was petroleum gas. Herron promptly bought 700 acres in the area where the seepages occurred. Through succeeding years he was continually in the habit of buying mineral leases from the Dominion government. During the rest of his life he was alternately rich and poor; he could not leave the risky oil industry alone, and even today his sons are engaged in the Alberta industry.

Herron began to try to persuade Calgarians to provide cash for drilling operators. This was no easy task. He finally succeeded in getting two Calgary businessmen, William Elder and the ubiquitous Archibald Wayne Dingman, to agree to come to his holdings for a demonstration. According to the story, Herron brought the men to a spot where gas was escaping, touched a match to a rock fissure, pulled out a frying pan, and casually began frying eggs. Both Elder and Dingman were suitably impressed. A syndicate was formed which obtained more than half the interest in the properties of Herron and promised to drill for oil. The syndicate was then incorporated as the Calgary Petroleum Products Company, and it spudded in a well along Sheep Creek, January 25, 1913, which was destined to go down in history as the "Dingman Discovery", named after Dingman who was in charge of drilling. It is now known as Royalite No. 1.

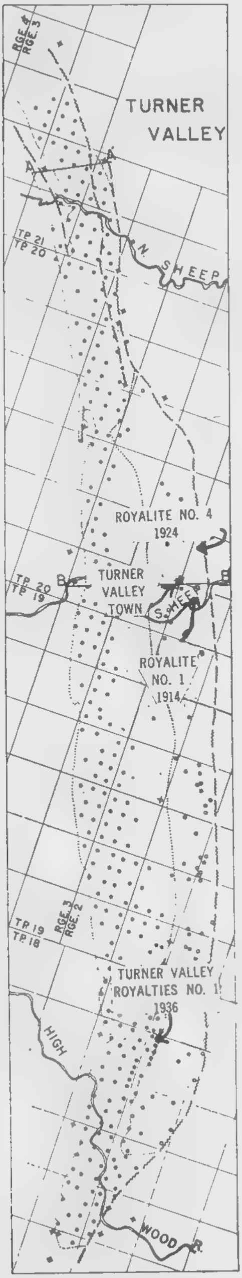


Fig. 11 The Turner Valley Oil Field

Excitement in Turner Valley and Calgary mounted as the pounding bit of the cable-tool rig released bursts of gas and showers of crude oil, first encountered definitely at 1,557 feet. In May, 1914, at a depth of 2,718 feet, the well blew in with a flow of some four million cubic feet daily of "wet gas" saturated with a straw-colored light oil, of such a light gravity that it was used at once to operate the unsophisticated automobiles at the well site. The discovery was made in Lower Cretaceous sandstone and the well was subsequently deepened to 3,825 feet.

This was the beginning of the Turner Valley field which for more than 30 years, until Leduc came in, was the chief oil field not only in Alberta but in Canada. The boom that followed the Dingman discovery sent Calgary into a frenzy. Brokerage houses sprang up throughout the city and literally hundreds of oil companies were formed overnight. Most people with dollars in their pockets strove to get in on the ground floor and as much as half a million dollars changed hands in one day. The Calgary Stock Exchange had been established previously in the corner of a local butcher shop. The day after the Dingman well blew in the brokers abandoned their cash drawers and began piling the money in wastebaskets. Gaudily engraved share certificates were sold by the thousands.

Three months later the bubble burst. Speculators began to realize that production at Turner Valley was too modest to justify the enormous amount of oil paper on the market. Furthermore, nobody was really drilling any more wells! The outbreak of the First World War had a dampening effect. Most of the many hundred oil companies incorporated during the boom were wound up or became inactive. Today only two survivors remain, the Alberta Pacific Consolidated Oils and the Turner Valley Oil Company, both incorporated as Alberta companies in 1914. Only a small number of companies were absorbed by the relatively few

eastern Canadian and American companies then in the field. The Turner Valley boom was almost all home-made and locally financed.

Fortunes were made and lost regularly on the Calgary Stock Exchange, but they were as nothing compared to the millions that were thrown around by the "armchair drillers" in every pub and hotel lobby. Oil was the topic of conversation everywhere, even among the school children. The Palliser Hotel had opened in Calgary a few days after the Dingman discovery and for months its halls were jammed with would-be magnates. According to a story in the Calgary *Herald*, the following list of regulations was posted in the lobby of the hotel:

1. No well shall be drilled before 6 a.m. or after 3 p.m. Operations at that time are liable to disturb paying guests while in the midst of beautiful dreams of vast wealth and permanent gushers.
2. No more than one well shall be drilled in each leather chair or sofa during one time interval. It is exhausting to the furniture.
3. No well shall be drilled in a tone of voice which is audible within the three-mile zone and causes the skylight to flutter.
4. No well shall be drilled nearer than one foot to any door, window or passageway, and no line dispute shall be indulged in or any lease located in such areas.
5. No dry holes will be tolerated in the lobby. All wells brought in must be in the thousand-barrel class or better.
6. All shares offered are of the gilt-edged variety. No need to call for the prospectus of the company. Just throw your money up and get your receipt. You can later pass it on to your friend for a better consideration.
7. No well drilled in the lobby shall *stop* at shallow sand. Every well must run down *deep* and represent an outlay of not less than $100,000.

Despite the flurry of activity in Alberta, the oil strike at Turner Valley failed to create interest in Eastern Canada. A Calgary alderman and ex-Baptist minister, T. A. P. (Tappy) Frost, made an attempt to interest Torontonians. He shipped a barrel of oil on the train in May, 1914, to Toronto. He rode the streets and stood in front of store windows dishing out samples with a soup ladle and publicizing the oil like a carnival barker. The degree of his success was small in the skeptical Ontario centre.

The Calgary Petroleum Products Company survived the collapse of the boom. It deepened the discovery well and started two more. A small absorption plant was built to capture the vapours in the gas, but it was not an economical operation. In 1920 the plant burned down, making it imperative to provide more cash if the company was to continue to operate.

Shortly after, the company negotiated with Imperial Oil Limited and was successful in obtaining funds. Imperial Oil, today the oldest and largest company in Canada, had been incorporated under a Dominion charter in 1880 by a group of small refiners around Petrolia and London in Ontario. The company established marketing outlets in Central Canada and also in Western Canada during the agricultural settlement period. Its first western office and warehouse was set up in Winnipeg in 1883 and in the next year a bulk station was established at Prince Albert, Saskatchewan. As the settlement of the prairies proceeded, the company set up bulk stations and substations in the new centres of population in the area and also provided marketing outlets in British Columbia. This company organized the Royalite Oil Company as a subsidiary and Royalite took over the holdings of the Calgary Petroleum Products Company. That company had produced the total output of the Turner Valley "field" of 48,000 barrels over the period 1914-20 from a few wells. The new company, Royalite, was destined to become almost synonymous with Turner Valley; it discovered oil and gas, processed and gathered gas, and ultimately became a producer of sulphur.

Imperial Oil began the construction of Alberta's first modern oil refinery at Calgary in 1921. Royalite laid plans to drill more wells in Turner Valley. The existing wells, in Lower Cretaceous sandstone, produced only a little oil with considerable gas. In 1921 the Royalite Company contracted with the gas company in Calgary to supply the city with a badly needed supply of gas, and a pipe line was built to Okotoks to feed the main line of the gas company. Royalite then started drilling a new well in September, 1922, Royalite No. 4. The idea persisted that the wet gas and light crude oil found in the Turner Valley wells were derived from some major pool lying at greater depths; Royalite intended to test the deep underlying strata.

Royalite No. 4 penetrated the Lower Cretaceous sands in which other wells had obtained some production, without getting more than minor traces of oil. Drilling proceeded through the dense black Fernie shales and into the Paleozoic Mississippian (Rundle) limestone beneath. Hopes waned for previous experience had shown the limestone to be unproductive. A little farther down some foul-smelling gas was found, and after another 300 feet or so into the limestone it was decided to abandon the test. On October 14, 1924, Clarence Snyder, who was in charge of the drilling at the time, received orders from head office to cease drilling. Since the crew had to be paid for the whole shift ("tour" in early oil jargon) and several hours of the "tour" remained, Snyder ignored the cease-drilling order for the time being and decided to keep his men working to the end of it. With just ten more feet into the limestone, a burst of tremendous gas pressure was met. Royalite No. 4 spewed forth gas and condensate in a wild flurry. The crew struggled vainly for three weeks to control the flow

and on November 9, to add to the excitement, the gas caught fire, a fire which it took more than ten days to put out.

Eventually the well was brought into production at a rate of 500-600 barrels per day of naphtha, a very light oil. It was delivered by six-horse teams to Okotoks until a four-inch pipe line was built to the Imperial Oil refinery in Calgary. The naphtha, which is a very high-grade crude used in making gasoline and other high-quality petroleum products, sold for three to five dollars per barrel, and the well yielded nearly one million barrels during its short life, making it just about the most profitable well ever drilled in Alberta. Output fell off rapidly in 1929 after a few years of flush production, and after unfruitful attempts to revive it, it was mudded off. The gas from the well was treated in a scrubbing plant that was built for the purpose, hydrogen sulphide was separated from it, and the treated gas was piped to Calgary.

The coming in of the well set off a chain reaction of drilling and dozens of rigs churned up the rolling countryside. More than two hundred wells were drilled during the next 12 years, mainly for naphtha recovery. Large quantities of natural gas for which there was little market were burned off to secure the naphtha and the flames could often be seen in Calgary, 30 miles away. The fearful flares burned night and day and turned the country into what was referred to as "Hell's Half Acre", a yawning chasm that spouted flames for 14 years until Alberta established a conservation board in 1938 with enough legal powers to force operators to produce naphtha and then crude oil in orderly fashion. Until that time it proved very difficult to persuade numerous small independent operators to adopt the scientific methods of production urged by the large companies and their personnel. The latter had difficulties in applying such methods to their own properties since oil and gas are migratory and come to the surface in whatever holes are drilled in a field; the independent operators were anxious to get their investments back in as short a time as possible and drilled wells accordingly.

Old-timers can remember hunting rabbits at midnight by the light of the flares. Flowers bloomed the year around and during the depression of the thirties homeless unemployed men huddled beside the fires for warmth. Royalite constructed an absorption plant in 1933 to recover additional gasoline from the "wet" natural gas of so many of the wells in the valley, but it was hopeless to try to make use of all the gas, for the markets for it were entirely inadequate.

For years after 1924, exploration and drilling were confined largely to the northern and central part of the Turner Valley gas-oil formation. There was, however, a growing belief that a great crude oil field might be found by drilling to greater depths than attempted previously on the southwest flank of the field. Many experts scoffed at the idea and main-

tained that the limestone-producing formation was cut off to the west by faulting or by water, but there were others who harboured the idea that a pool of crude oil did exist in Turner Valley.

One man was determined to find out. He was Quebec-born R. A. Brown, Superintendent of the Calgary Electric Light and Power Department. He followed the oil development in Turner Valley closely after 1924. After computing the gravity of the oil in several wells, he became convinced that the lower area would yield crude oil. It was a geological hunch of a non-geologist, but he was not entirely a layman for Brown was an electrical engineer. Engineers receive a fundamental education in the sciences and they have a way of turning up as practitioners of many arts. Brown went to Imperial Oil and the British American Oil Company to obtain funds; both made contributions although they were dubious of the venture as they had every right to be in view of past experience and existing geological knowledge. The *Financial Post*, in its June 9, 1956, issue, states the situation as follows:

> "In spotting their discovery well, Turner Valley Royalties, Brown was acting on a geological hunch, not supported by the theory of any competent geologist. He wanted money to put his hunch to the test and went to Imperial Oil.
>
> " 'They were not a damned bit impressed with my geology,' Brown, an electrical engineer, says, 'and they had no right to be because I didn't know a damned thing about it. But they gave me $25,000. I got another $30,000 from B-A who, with good reason, were as skeptical as Imperial. This gave me a start, and we brought in Turner Valley Royalties.' "

Brown persuaded two men to work with him, George M. Bell, the main owner of the Calgary *Albertan,* and Jack W. Moyer, who had some experience in the oil business. It took them three years to raise the necessary $125,000 for equipment. Drilling started on Royalties No. 1 on April 17, 1934, with a cable tool rig, and seven times during the next two years operations were halted for lack of money. At a depth of 3,180 feet a rotary rig was brought in to do the work.

On the evening of June 16, 1936, when a depth of 6,828 feet was reached, a gusher of green crude oil hurtled high into the derrick with a thunderous roar. Initial production from the well exceeded 850 barrels per day. It was the deepest well that had been drilled in Alberta until that time and it indicated that there was a reservoir of crude oil in Turner Valley's southwest flank that awaited deep drilling to tap it. The Royalties discovery well produced more than 700,000 barrels of light crude oil worth about two million dollars over the period 1936-49.

The Royalties discovery led to a flurry of drilling activity, and various oil companies brought in a number of producing wells during succeeding

years. Between 1936 and the end of 1941, nearly 200 wells were drilled of which only a half dozen turned out to be dry holes. Eventually the Turner Valley field had more than 300 producing wells.

There were marketing difficulties because existing pipe-line and refining facilities were inadequate to handle the rapid increase in crude oil production. Without some system of "prorationing" as it is termed in Alberta (cf. the equivalent term "prorating" as it is known in the United States), to regulate the output of each producer and of each of his wells, production and marketing become chaotic. Some producers found that they had to shut off the flow of crude for lack of storage space while others tried to dispose of their surplus by drastic price cuts. In Turner Valley, Imperial Oil was the largest purchaser of crude oil and to create some order, the company set up a system of quotas to be purchased from each well each month. As new wells came in the quotas had to be adjusted downward for the old. The quotas varied with the amount of oil available, refining capacity and the demand for refined products. Both Imperial and the producers of crude became dissatisfied with this state of affairs, the former because it was continually criticized for not buying all that the wells could produce and the latter because they felt they were not able to sell enough crude.

The provincial government intervened and set up a Conservation Board in July, 1938, which worked out a quota per well each month. In addition, this board imposed conservation measures which had been needed badly. The province took another step in dealing with the problems of the Turner Valley oil industry by appointing a Royal Commission in October, 1938, to inquire into the Alberta industry. The commissioners were Justice A. A. McGillivray and Mr. L. R. Lipsett.

The Commission prepared a report, now usually referred to as The McGillivray Report, which was completed in April, 1940. It dealt with all phases of the oil industry pertaining to Alberta. The conclusions of the commissioners were many and cannot be reproduced here. The commissioners indicated and canvassed the complexity of the oil industry, set out estimates of the life of the Turner Valley field, pointed out the necessity for orderly marketing procedures and recommended a three-man conservation and prorationing board. Suffice it to say here that the provincial government board, set up in 1938, gradually worked out conservation and prorationing measures which helped to stabilize production and to prevent waste in the Turner Valley field. It also obtained nine years of crucial experience, direly needed when Leduc and other major oil fields were found in Alberta after 1946.

During the late 1930's many Turner Valley producers pressed for a pipe line to the Great Lakes. The McGillivray Report found it to be uneconomic because known reserves in the field were too small to amor-

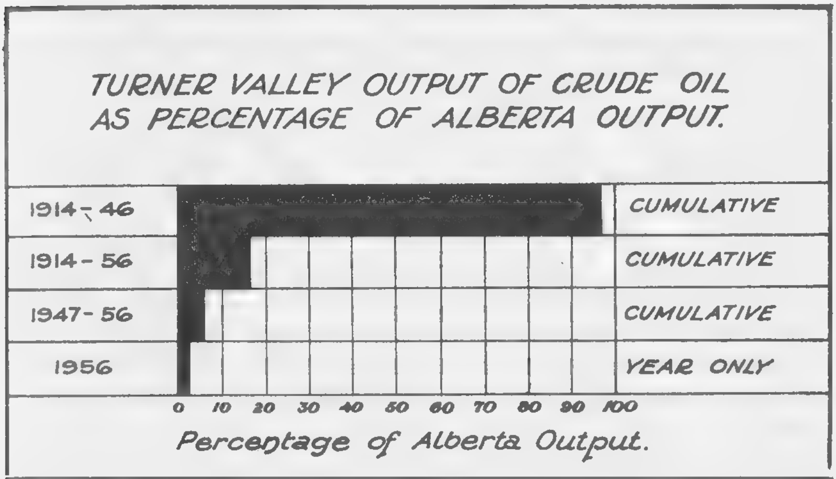
tize and pay the cost of operating it. Then came the Second World War and with it a great demand for oil from any North American sources that could be found, and the potential of such fields as Turner Valley in remote Alberta and Norman Wells in the even more remote Northwest Territories, suddenly became very useful and valuable. Turner Valley oil production was increased materially during the war years, a measure which shortened the life of the field.

Turner Valley is still a producing oil field, but instead of ranking first in Alberta (as well as in Canada) it has slipped to fourteenth place in the province as of 1956. Fig. 12 shows the rise and decline of the field as a crude oil producer. Before 1926, when the Wainwright field came into production, it was the sole producer of crude oil in Alberta. For the total period 1914-46, before the Leduc and other major discoveries came in, it accounted for almost 97 per cent of the crude oil produced in Alberta. It attained a peak output of 9.7 million barrels in 1943, almost 95 per cent of the total Canadian output. After that date, the output of the field has declined rapidly to a current level of about two million barrels annually. In 1956 it accounted for a puny 1.4 per cent of the total Alberta output. During the 1947-56 decade it provided only five per cent and with the increasing flow of oil from the new fields discovered after 1946, its cumulative contribution of 112 million barrels for the period 1914-56 amounted to only one sixth of the 674 million barrels produced in Alberta. The field still remains the leading natural gas producer in Alberta (and Canada), but even this distinction is likely to be taken away from it in the near future.

What is the significance of Turner Valley and what can be said of its future? The field has been worked over by oil men now for decades. Drilling in the area is deep because it lies in the foothills, and the present 300-odd producing wells average about 7,700 feet in depth with average pay zones of 145 feet. The productive formation is limestone of Mississippian age called Rundle after Mount Rundle which, in turn, was named after an early missionary among the Indians in Alberta. The rock is difficult to penetrate, which, together with the great depth, makes for expensive drilling. Because of the irregular, folding and repetitive structure of the subsurface of the area, it is difficult to predict success in finding oil at any given location.

Turner Valley was the pioneer which provided the initial funds for the petroleum industry in Alberta. The discoveries in the field encouraged the exploration for oil elsewhere in the province. It was the "pilot-plant" which proved most valuable when the great postwar discoveries were made. It made Alberta the "oil province" many years before Leduc came in, and it established Calgary as the management centre of the petroleum industry in Western Canada.

The indiscriminate methods of production applied during the 1925-38 period when wells were often permitted to flow immoderately reduced the gas cap and water drives of the field. This has led to a great decrease in the rate of production since 1943. The total amount of oil



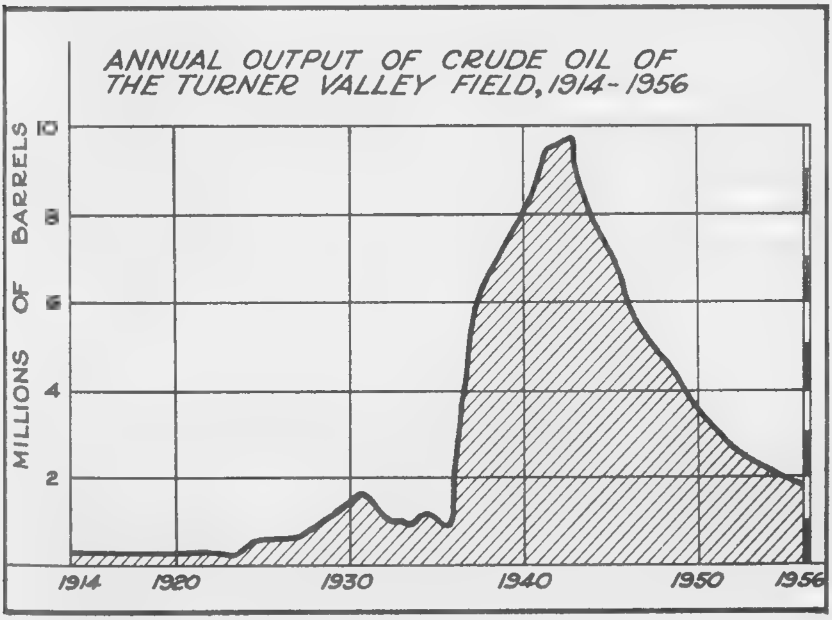


Fig. 12 The rise and fall of the Turner Valley Oil Field, 1914-56
Source: PNGCB

recovered will be only a small fraction of the total content of the reservoirs, probably between 10 and 15 per cent. Secondary recovery methods, such as water injection, are used for some wells, but the money spent on these must be balanced carefully against the money that can be obtained from additional oil recovered by such methods. It may be more economical to spend the money on exploration and drilling elsewhere. The Home Oil and Royalite companies, which operate most of the wells in the field, are currently attempting to apply secondary recovery techniques in the field.

The main towns and villages of the area, Turner Valley, Black Diamond and Hartell, attained their maximum size during the war years of the early forties. Since then their populations have declined as explorers, drillers, well operators and administrative personnel have moved to other oil and gas fields in Alberta. Between 1946 and 1956 the combined populations of the towns fell by a little more than one third. Sudden increases of population when oil is found, followed by a period of little change as well and pipe-line operators replace drillers who move out, and ultimately followed by decline as well operators and other production workers leave, are a familiar sequence in the economic evolution of localities in which oil is found.

On June 16, 1956, the Canadian Petroleum Association joined with many western oilmen to celebrate the twentieth anniversary of the discovery of Alberta's first major crude oil well and to pay tribute to the pioneers in the province's petroleum industry. To commemorate the event, a cairn in the form of an 18-foot concrete oil derrick was erected on the main corner of the Town of Turner Valley. The cairn stands within sight of the first Dingman well. In the June 9, 1956, issue of the *Financial Post* a writer said very fittingly: "Turner Valley is today enjoying a venerable old age. It is full of honours as Canada's first oil field."

Other Discoveries Before 1947

Various crude oil discoveries were made in Alberta before 1947. They were of small importance beside the Turner Valley field, but they helped to keep exploration activity alive in the province. Altogether, 17 fields were discovered outside the Turner Valley area between 1925 and 1946. Nine of these fields are no longer producers and they can hardly be called "fields" because altogether they produced less than two million barrels during the 30-year period of 1927-56. The eight remaining fields have produced only about 13 million barrels during the same period. In recent years, however, a few of them, notably Lloydminster and Wainwright, have achieved some prominence. In 1956 the

eight fields produced a little more than two million barrels, about one and a half per cent of the total Alberta output.

The main reason why most of these fields were discovered early is that in so many of them the oil reservoirs are embedded in shallow formations of Lower Cretaceous age. Unfortunately the pools of oil found are generally small, the crude is often heavy and black and asphaltic, and pumping is necessary to bring the oil to the surface. Turner Valley oil is of a light, high quality which varies from 35° to 73° API; the gravity of much of the oil found in most of the other fields discovered before 1947 was generally between 10° to 15° API.

It may be helpful to point out here that some years ago the American Petroleum Institute revised what was called the "Baume" system for measuring and recording the relative weights of oils. Crude oils are now identified by "degrees API" (API meaning American Petroleum Institute) and they generally range from 5° to 65° API. The lighter the oil is, the higher the degrees API, and the greater the quality and price per barrel tend to be. Light oil contains naphtha and other ingredients which yield a high percentage of gasoline without repetitive refining processes. The heavier the oil is, the lower the degrees API, and the lower the quality and price per barrel tend to be. The heavy crudes yield gasoline grudgingly and often only after considerable cycling and recycling in refineries to remove not only asphaltic materials but also impurities like sulphur which, by combining with hydrogen and oxygen, can form sulphuric acid and eat away at the internals of motors. Another disadvantage of the heaviest crudes is that they cannot be transported easily by pipe lines, especially when temperatures are low. Heavy crudes yield large quantities of asphalt and fuel oil; if markets for these are available, crudes with low degrees API may be very valuable. A 65° API oil weighs about six pounds per gallon and a 5° API oil more than eight and a half pounds.

The second oldest field in Alberta is that at Wainwright, about 150 miles southeast of Edmonton, and it was discovered in June, 1925. Here oil was struck in Sparky sandstone of Lower Cretaceous age. The oil is a heavy crude measuring from 18° to 20° API. For many years the market for the oil has been small, and it is only in very recent years that production from the field has risen to significant proportions. Wainwright Producers and Refiners Limited, a company affiliated with American Northland Oil Company, operates most of the wells in the field as well as a refinery in the town of Wainwright. The company has a contract to supply the Canadian National Railways with large amounts of diesel fuel; as a result there has been intensive drilling going on during 1955 and 1956. More than 100 wells now pump oil from depths and pay zones averaging 2,200 feet and 20 feet respectively. The 1956 output was about 300,000 barrels, approximately two fifths of the total production for the 30-year

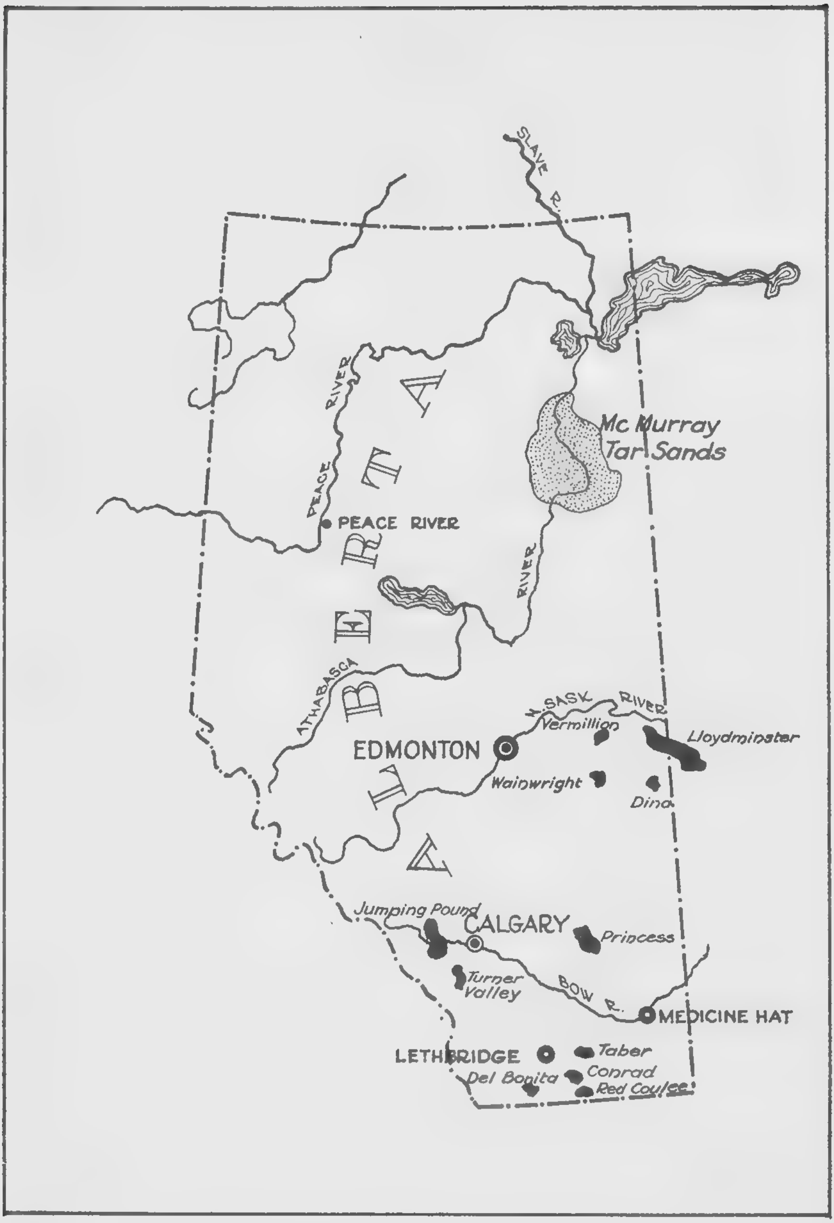


Fig. 13 Crude-oil fields in Alberta in 1946

period of 1926-55. It is remarkable what markets can do to make a resource active and valuable. In this case, the decision of the railways to burn oil instead of coal and the high level of provincial highway construction, requiring much asphalt, have finally brought life to the field. A dilapidated refinery of the "still" type stands beside the discovery well, a few miles north of Wainwright. The well is still a producer, and a ceremony was held in 1956 to commemorate its 30-year existence as such. The old refinery is defunct, but despite its fire-ravaged appearance, it would make many a Kentucky or Tennessee hillbilly think he had reached the height of success in life if he had it tucked away in a large enough bushy gorge or ravine.

The next Alberta discovery came in 1927 at Skiff, southeast of Lethbridge. Production was very small and ceased altogether after 1936. In 1928 a discovery was made at Dina, south of Lloydminster; this field has a few wells which have produced small quantities of heavy crude from a Lower Cretaceous formation about 1,800 feet in depth. In 1929 came a discovery at Red Coulee, near Skiff; this field reached a peak production of 65,000 barrels in 1931 and then declined to nothing after 1946. In 1932 oil was found at Del Bonita, on the international border, due south of Lethbridge; in 1956 it produced about 30,000 barrels from a Rundle Mississippian limestone formation with an average depth of 5,100 feet. Traces of oil were found in 1933 at Keho, north of Lethbridge, and in 1937 at Moose Dome, near Turner Valley; production was very small and soon ceased. A field which is still a producer of a 23° API crude from Lower Cretaceous sandstone was discovered at Taber, east of Lethbridge in 1937.

The year 1939 brought several discoveries of more than passing importance. One was that in the Princess-Bantry area, 140 miles southeast of Calgary; it is notable because it was the first field in the plains area of Alberta to yield oil from Devonian and Mississippian limestone; it also produced from Lower Cretaceous sandstone. The crude rated intermediate, from 24° to 32° API, and almost one million barrels have been produced to date. The output is very small today. When the large fields of Leduc and Redwater were discovered, most of the interest in the Princess-Bantry field waned even though drilling depths were less than 4,000 feet.

Heavy crude was found in 1939 at Vermilion, 35 miles north of Wainwright, in Sparky Lower Cretaceous sandstone at a depth of less than 2,000 feet. There was considerable production from the field during the forties but it has now practically ceased. The crude is very heavy, from 7° to 10° API, making it inferior even to the heavy crudes of the neighbouring Wainwright and Lloydminster fields.

The most significant find of 1939 was that at Lloydminster, about

25 miles east of Vermilion. Heavy crude oil with a gravity from 9° to 17° API was found in the Sparky sandstone characterizing the Wainwright and Vermilion fields and at depths just under 2,000 feet. Production in the Alberta side of the field was insignificant until 1945 when it rose to 28,000 barrels from about 6,000 barrels in 1944. Since then it has increased rapidly and it exceeded one million barrels in 1952 in the Alberta portion. Production is still rising and a larger fraction of it comes from the Saskatchewan part of the field than from the Alberta portion. The cost of developing the field is relatively low, but until the railways embarked upon a policy of conversion from coal to oil, development proceeded slowly. There are two refineries in Lloydminster operated by the Husky Oil and Excelsior Oil companies. Husky has been particularly active in drilling development wells, but there are many small independent companies operating wells in the field. Since there is no gas cap or water drive to force the oil up, pumping is required. Wells may be spaced at one per 10 acres in contrast to one per 40 acres so common in most Alberta fields. The Alberta part of the field has more than 400 wells, about six per cent of the total number in the province, but produces only about one per cent of the Alberta output of crude.

There were further discoveries during the early forties. Intermediate crude oil with a gravity of 26° API was found in 1944 at Conrad, southeast of Lethbridge, in Jurassic sandstone, a formation which never before had yielded oil in the province. The field, however, is a small producer, about 100,000 barrels in 1956. There was a flurry of excitement over a find at Ram River, nearly 100 miles west of Red Deer in the foothills, in 1944. Nothing came of it after about 200 barrels were produced in the same year. Small amounts of oil were found at Tilley, near Princess, in 1942; at Armelgra, west of Medicine Hat, in 1943; and at Provost, southeast at Wainwright in 1946; but production in these areas soon ceased as the pools were entirely too small for economical operation.

Finally, a field of great significance was found by the Shell Oil Company at Jumping Pound, about 20 miles west of Calgary. It is not really an oil field, but a "wet" gas field which is capable of producing some very light oil. To the end of 1956 it had produced less than half a million barrels of such oil (condensate). The real importance of the field lies in its great natural gas potential which has come to serve the city of Calgary increasingly and has led to the construction of sulphur plants in it. The potential will be used even more as the Trans-Canada natural gas pipe line comes into operation. Drilling in the field has been done to depths exceeding 14,000 feet to Mississippian limestone formations of the Turner Valley type. Indeed, the deepest well in Western Canada, the Shell Jumping Pound Unit 4, was drilled by Shell Oil in this field to a depth of 14,443 feet.

By and large, before 1947, the indications of oil in the province were spotty and, except for the heavy crude oil finds, they occurred mainly in the southern prairie and foothills portion of the settled territory of Alberta. The heavy crude fields of the eastern part of the Edmonton region did not develop until the railroads shifted from coal to oil and the provincial government, staked by revenues from the postwar discoveries, began to build hard-surfaced highways in earnest.

In Alberta, more than 70 discoveries of natural gas were made between 1883 and 1947. They were made chiefly as a result of drilling for oil. The major gas fields which were developed commercially to provide fuel for Alberta cities and towns during the pre-1947 period were those around Medicine Hat, Bow Island, Turner Valley and Viking. We shall reserve the description of these discoveries for a subsequent chapter on natural gas. The fields discovered before 1947 were sufficient to meet Alberta urban requirements and new wells were drilled in established fields only as natural gas utility companies required additional supplies. After 1946 gas discoveries have been frequent and substantial as a result of the widespread search for oil.

Our story would be incomplete without a reference to Norman Wells in the Northwest Territories (see fig. 7), some ninety miles south of the Arctic circle, where Imperial Oil had carried on an exploration and development program since 1918. Here, as early as 1919, Imperial geologist T. A. (Ted) Link, who is to western Canadian oil exploration what Babe Ruth was to baseball, is said to have waved his arm in the air and pointed to a spot in the vicinity and told the long-awaited drillers, newly arrived and weary after a long and arduous journey from Edmonton, to go to work. They did so, and after months of hard drilling with their cable tool rig, they struck oil at 900 feet in the summer of 1920.

Oil seepages had been noted in the Norman Wells area by the ever-observant Sir Alexander Mackenzie in 1789 and by R. G. McConnell of the Dominion Geological Survey in 1888. In 1914 T. O. Bosworth, later Imperial's chief geologist, staked three claims and sent Link and an assistant geologist, Jack Zieman, to explore them in early 1919. Late in the year a six-man drilling crew arrived with their equipment after a journey from Edmonton to Fort McMurray by railroad, and from there by river steamers and portage to Norman Wells. The crew, relieved by newcomers, drilled two more successful wells and a dry one. The local market for the oil was very small and the distance to Edmonton, the nearest potential market, was 1,500 miles by water and rail.

During the thirties, large deposits of silver and uranium were discovered at Great Bear Lake, 300 miles northeast of Norman Wells, by Gilbert A. La Bine. Imperial constructed a small 500-barrel-per-day refinery at Norman Wells which began operations in 1933 to provide fuel for the

new mines. In 1935 came the discovery of the Yellowknife gold field and a new prefabricated refinery with a capacity of 840 barrels per day replaced the old. Then came the Second World War, and by 1942 the Japanese had occupied the Aleutian Islands off the coast of Alaska. The Alaska Highway was built jointly by the Canadian and American governments to supply the troops defending Alaska. But it was realized that tank trucks hauling oil from railheads in the Peace River region would use up so much of their loads that Alaskan supplies would be inadequate. Imperial, and the Canadian and American governments, evolved a plan to build a pipe line from Norman Wells to Whitehorse, Yukon, a distance of nearly 600 miles. The U.S. engineers completed it by February, 1944; they also constructed a refinery at Whitehorse and three pipe lines to carry products from it to Watson Lake, Yukon, and to Skagway and Fairbanks in Alaska. Imperial sent drilling crews to Norman Wells who completed 60 wells which supplied the pipe line to Whitehorse with up to 4,000 barrels of crude oil per day until the end of 1945 for a total over the period of more than one million barrels. The whole project was familiarly known as the Canol, an abridgment of "Canadian" and "oil".

After the war, the Canol pipe line was dismantled, for pipe was scarce during the postwar days. Imperial purchased the Whitehorse refinery and moved it in 1948 to process Leduc crude oil, giving Edmonton its first refinery. The Norman Wells refinery still continues to operate to supply the silver, uranium and gold mines in the far north with fuel. With the construction of the DEW line since early 1955, the refinery has been able to operate on a year-round basis and it has diversified its products.

6

Pre-Leduc

In 1946 there were more than one hundred oil and gas companies in operation in Western Canada. Eleven Canadian and American major integrated companies were actively engaged in exploration and development in the region and so were four Canadian major independent companies. About 50 minor companies produced some oil, chiefly in the Turner Valley field, and some of these occasionally engaged in some exploration activity. There were also more than 50 minor companies with interests in petroleum acreage in the region. In addition, there were sundry royalty companies.

At the end of 1946 the total assets of these companies, excluding the American ones, were considerably below half a billion dollars. The three major integrated Canadian companies, Imperial, British American and McColl-Frontenac, accounted for more than 70 per cent of this, and most of their assets were located outside Western Canada in the form of refineries, pipe lines and marketing outlets in Eastern Canada. Imperial had large South American subsidiaries, British American had a subsidiary in the United States (The British American Oil Producing Company) which produced crude oil from more than 400 wells in ten different states, and McColl-Frontenac had a subsidiary producing oil in Trinidad, the Antilles Petroleum Company. It is doubtful if the three companies had a combined investment of 100 million dollars in Western Canada. The other hundred-odd companies would together account for no more than 50 million dollars of investment. The largest had total assets of a little more than four million dollars and many of them had assets in the order of one hundred or two hundred thousand dollars. The industry, then, consisted of three very large Canadian companies, a few United States majors with "feelers" in Western Canada and more than 100 companies with assets varying from a few thousand to a few million dollars.

Imperial Oil, mainly through its subsidiaries Royalite and the Foot-

hills Oil and Gas Company operating in Turner Valley, accounted for a little more than one third of crude oil production in Alberta (and Western Canada) in 1946. Royalite, in turn, controlled another producing and development company, Dalhousie; its wholly owned subsidiary, Valley Pipe Line Company, formed in 1939, operated 105 miles of gathering lines, two four-inch and one six-inch trunk lines from the Turner Valley oil field to refineries at Calgary. These lines were the only crude-oil pipe lines in Western Canada in 1946 except for 5½ miles laid in the Conrad field and 3½ miles laid in the Princess field by the California Standard Company in 1945. The first trunk line of the Valley Pipe Line Company was completed in 1925 while the other two were laid in 1937 and 1938. The lines had a combined capacity of 24,000 barrels per day. The gathering lines, varying in diameter from two to four inches, were constructed over the years as the Turner Valley field developed.

Royalite also owned and operated a gas scrubbing plant in Turner Valley with a daily capacity of 90 million cubic feet, delivering the processed gas to the Canadian Western Natural Gas Company, the gas distribution utility serving Calgary. Further, it owned and operated two absorption plants in Turner Valley with a capacity of 175 million cubic feet daily for extracting gasoline from the "wet" natural gas found so prevalently in the field. A wholly owned subsidiary, the Madison Natural Gas Company, operated the natural gas division of Royalite.

Out of the 20 refineries operating in Western Canada in 1946, Imperial owned four with a combined crude charging capacity of 35,650 barrels per day, a little more than half of western Canadian capacity. They were located at Ioco (Vancouver, British Columbia) with a capacity of 16,000 barrels per day, Regina, Saskatchewan (10,500 barrels per day), Calgary (8,300 barrels per day) and Norman Wells (850 barrels per day). The Calgary refinery represented nearly half of the capacity of 17,100 barrels per day of the four refineries operating in Alberta. Finally, the company owned bulk plants and service stations throughout the region. It was the only company which had achieved a high degree of integrated operations in the region by 1946, from its active exploration program to its ubiquitous service stations.

The British American Oil Company, usually known as "B-A", had assets of nearly 100 million dollars at the end of 1946, about half the value of those of Imperial, and spread throughout Canada and in many parts of the United States. It began to provide funds in Alberta for independent drillers such as Brown in 1935, retaining rights to buy crude oil and royalty rights in wells drilled. In 1943 it established a geological and production office at Calgary, but it did not obtain any commercial production until the post-Leduc era. In 1946 it operated two refineries in Western Canada, one at Calgary with a crude charging capacity of 5,500

barrels, and another at Moose Jaw, Saskatchewan, with a capacity of 5,200 barrels, to account for about one sixth of western Canadian capacity. The company also had an absorption plant at Turner Valley with a capacity exceeding 80 million cubic feet of natural gas per day. This plant was unique in Western Canada in its production of feed stocks for alkylate which, combined with aviation stocks, makes aviation gasoline with a very high octane rating. British American also operated a gas storage and repressuring plant in Turner Valley, completed in 1944, to assist in recovering crude oil and absorption gasoline. It was the main rival of Imperial in the marketing field, with bulk and service stations distributed throughout the prairies; it extended its marketing operations to British Columbia in 1945 when it purchased the assets of Union Oil of Canada.

The McColl-Frontenac Oil Company, an associate of the Texas Company, with assets of about 50 million dollars, was active in Western Canada mainly through its marketing of petroleum products under the trade name of Texaco. It began an exploration program in Western Canada in 1941; by the end of 1946 it had drilled more than 20 wells, some in association with Union Oil Company of California, but found no oil. The two companies discovered several gas wells in southeastern Alberta in 1946. The plan of McColl-Frontenac to build a refinery at Calgary in 1941, its first in Western Canada, had to be abandoned because of the shortage of construction materials during the war.

We have to step down a long way in considering other oil companies in Western Canada in 1946. Four independents with combined assets of 12 million dollars, Home Oil, Anglo-Canadian, now part of Canadian Oil Companies, a large Canadian independent, Pacific Petroleum and Okalta, produced about one quarter of the crude oil output of Alberta (and Western Canada) in that year. The first two of these were particularly active in exploration work and Anglo-Canadian had a three-eighths interest in Anglo-Canadian Oils which operated a refinery with a daily capacity of 2,000 barrels at Brandon, Manitoba. It is not possible here to name all the small producing companies in the Turner Valley field and elsewhere in Western Canada.

The Shell Oil Company operated a refinery at Shelburn (Vancouver) and had service stations throughout British Columbia. It was also active in exploration as we have noted. Several refining companies operated the rest of the refineries in Western Canada and most of them also maintained bulk and retail outlets. In Alberta, there were Excelsior Refineries with a 1,000-barrel-per-day refinery at Lloydminster, Turner Valley Gas and Oil Refineries Limited with a plant at Hartell in the Turner Valley field with a capacity of 2,200 barrels per day, and Gold Standard Oils with a very small 300-barrel-per-day refinery at Wainwright. The Husky

Refining Company was constructing a 2,500-barrel-per-day asphalt type of unit at Lloydminster. In British Columbia, Standard Oil Company of British Columbia, a subsidiary of Standard Oil of California, operated a refinery at Burnaby (Vancouver). In Saskatchewan, Hi-Way Refineries Limited had very small units, about 300 barrels per day each, at Moose Jaw, Rosetown and Saskatoon; the Consumers Co-operative operated a small refinery at Regina, and Northern Petroleum had the distinction of running the smallest refinery in Canada, with a capacity of 200 barrels per day, at Kamsack. In Manitoba, North Star Oil operated a refinery at St. Boniface; Radio Oil Refining, one at Winnipeg; and Trump Oil Company, a very small one at Morris.

This, then, was the petroleum industry in Western Canada in 1946. Led by Imperial, it spent in that year an estimated 12 million dollars on exploration and development activities, had 11 geophysical parties in the field and 19 drilling rigs in operation, and drilled 600,000 feet of "hole" to complete 182 wells. Of the 130 wells drilled in Alberta, 54 were exploratory, of which 46 were "dry holes", three found oil and five found gas, a most uninspiring record. Development drillers naturally had a better time of it since they worked, for the most part, in partially proven territory. The Lloydminster field with its shallow wells accounted for many of the wells drilled; unfortunately, the low-quality heavy crude oil of the field for which an adequate market was only in a stage of early development provided only a meagre reward. The Turner Valley record was also very good, but the deep and difficult drilling provided diminishing net returns to the companies. During the year Imperial drilled many wells in the Viking-Kinsella gas field to delineate its boundaries and to search for a gas supply which might be processed into gasoline; a large part of this field belongs to the Northwestern Utilities which distributes gas to consumers in Edmonton. Here the drilling record was good as far as finding gas was concerned. In the rest of the scattered small fields of Alberta, results were disappointing.

Production of crude oil came mainly from Turner Valley and supplied the Calgary refineries and some surplus for those in Saskatchewan. It amounted to nearly all the oil produced in Canada. Fourteen companies operated 20 refineries in the four provinces with a little less than 30 per cent of the total Canadian capacity. Twelve refineries, concentrated mainly in the Montreal, Toronto and Sarnia areas had the rest of it; because of the greater density of population in the St. Lawrence Valley, refineries are larger there, on the average, than in Western Canada where long-distance hauls are common. Finally, Western Canada had a well-developed, highly competitive system of bulk and service stations selling gasoline and other petroleum products under the trade-marks of more than a dozen companies.

The pipe-line transportation, refining and marketing activities of the industry paid their way, on the average. Turner Valley production was repaying previous spendings on exploration and development and it provided some funds for exploration. By and large, the industry in Western Canada depended little on outside funds in 1946.

It has been estimated that the industry spent nearly 200 million dollars, exclusive of royalties, on exploration, development and producing during the 30-year period of 1917-46. Of this, more than four fifths was spent in Alberta, less than a tenth in Saskatchewan, a fifteenth in the Northwest Territories, and a negligible amount in Manitoba and British Columbia. More than half was expended on development drilling and one eighth on producing, that is, bringing oil to the surface from proven wells. The rest was used to acquire land, make geological and geophysical surveys and to drill holes. The cost of acquiring land was low, and only an estimated 10 million dollars was paid to original owners of petroleum rights during the 30 years. Currently the industry is spending annually in excess of half a billion dollars on exploration, development and production in Western Canada. After allowing for the great rise in the level since the 1920's and 1930's, this is still greater than the total spent over the 30-year period of 1917-46. And the Alberta government collects as much as 100 million dollars or more from the industry in a year for petroleum rights.

The estimated total revenue from crude oil and gas over the 30-year period was somewhat in excess of the expenditures of finding and producing oil; thus the industry, on an over-all basis, had recovered funds spent to obtain oil and gas. Many companies and operators, of course, obtained little or no return; this is a common occurrence in the exploration phase of the industry. Those who did recover their expenditures, and more, had funds for further exploration. According to the Alberta Petroleum Natural Gas Conservation Board, virgin recoverable reserves of crude oil and condensate discovered until the end of 1946 amounted to 157 million barrels of which 85 million barrels had been produced through the years. With the increasing oil shortage in Western Canada in 1946, the industry could not sit still and merely let the remaining reserves run out.

The companies did not do so because the region, particularly Alberta, had large sedimentary basins which seemed favourable to the oil prospector. The region itself presented a market for oil and its products since it imported much of its requirements. When the large discoveries came after 1946, the region presented exceptionally good opportunities for the companies already in it. There began an influx of American and other companies which had hesitated previously to come to Western Canada. It was safe, familiar territory devoid of unpredictable Middle East sheiks

and South American revolutionaries; the governments and people are fundamentally similar to those of the United States. Furthermore, the cost of finding oil in the United States was rising and so was the price of crude oil.

The Oil Supply in Western Canada in 1946

Before Turner Valley became a producer of crude oil in 1936, most of the crude used by Alberta and Saskatchewan refineries came from the United States, much of it from the Cutbank field in Montana. In 1936 the price of crude oil in Calgary was a composite of the price of crude in the Montana fields plus the cost of rail transport from them to Calgary. The price was higher for the refineries of Saskatchewan and Manitoba for they had to pay freight on crude for longer distances than those in Calgary. As production from the new Turner Valley field rose, the price of crude declined and imports from the United States gradually diminished. By 1940 Alberta imported little crude oil while a southern strip of the province imported refined products. Exports of Turner Valley crude to Saskatchewan rose greatly, and in 1941 the Turner Valley field supplied practically all the requirements of the main Alberta and Saskatchewan refineries.

Wartime demands made it impossible for Turner Valley to supply both provinces and the price of crude oil began to increase accordingly. Alberta continued to be self-sufficient during the war years, but at the expense of shrinking exports to Saskatchewan. To obtain crude for the latter province, the oil companies had to go farther down into the United States because Montana supplies were becoming scarce. Crude oil was imported into Regina at the end of the war period from as far as Oklahoma at a rail transport cost of nearly two dollars per barrel. Manitoba had little refining capacity and imported refined products from both Eastern Canadian and Saskatchewan refineries.

The Alberta production of crude oil fell from a peak of 10 million barrels in 1942, sufficient to supply nearly all the requirements of Alberta and Saskatchewan refineries, to about seven million barrels in 1946 which did little more than supply the Alberta plants. With production diminishing from Turney Valley and prairie consumption rising, the domestic supply picture was bleak indeed. Even the Calgary refineries had to begin to consider imports of crude from the United States.

By 1946 the petroleum industry was studying seriously various alternative sources of crude oil. One was the possibility of supplying the prairie provinces with imported crude from Churchill on Hudson Bay

either by rail or by pipe line. Another possibility was to bring imported crude from Vancouver by rail. Still another was to import petroleum products from the United States, either by rail or by a products pipe line. All of these alternatives presented difficulties of execution and all of them entailed high costs. Imports of crude oil from the United States by rail continued throughout the year as well as into the next.

Some oil companies, both in Canada and the United States, began to give much attention to the problem of producing synthetic oil. Special chemical processes might have been used to convert Alberta natural gas into gasoline and other products. Imperial Oil undertook an intensive program of drilling in the Viking-Kinsella gas field, 70 miles southeast of Edmonton, during 1945 and 1946, in order to delineate the field and to find out if there were sufficient reserves to justify the construction of a synthetic gasoline plant. The drilling program established an increase in the proven area from 50,000 acres to about 250,000 acres and estimated reserves rose accordingly. When the Leduc discovery was made in 1947, the plans for a synthetic gasoline plant were shelved. The McColl-Frontenac and Union Oil of California companies proved up gas reserves similarly in the Pakowki Lake area, south of Medicine Hat, with the view of setting up a synthetic plant. If Leduc had not come in, and the production of synthetic gasoline from natural gas had been tried, the costs would have been forbidding in the short run, what with expensive experiments and pilot plant studies to be made.

Another alternative was to undertake a very costly program of developing a process for extracting the heavy oil from the Fort McMurray tar sands. Costs, when weighed against those of United States imports and those incurred for exploration in Western Canada, looked prohibitive, and the achievement of tangible results from investments in experimental and pilot plants appeared most uncertain to nearly all oil companies. Plainly it seemed that the Canadian prairies were doomed to endure high-cost oil.

However, it was largely a matter of time before a major oil discovery would be made. The prairie region was to be spared the restraints imposed on economic development by expensive petroleum products and Alberta was destined to become one of the major economic growth regions of Canada. Some time in 1944, Vernon Hunter, an Imperial Oil toolpush, stepped across the border from Saskatchewan into Alberta with his drilling crew, on his way to a meeting with destiny at Leduc. He had already acquired the nickname "Dry Hole" Hunter, and he did nothing to belie his seeming purpose in life until almost three years later. Let us turn now to the event which set off a chain of developments which made Alberta a surplus oil region and transformed the provincial economy.

7

Leduc

Wildcat One Hundred and Thirty Four

On November 20, 1946, an Imperial drilling crew, headed by Vernon Hunter, spudded in a well at a location 13 miles southwest of Edmonton and a few miles northwest of the town of Leduc (see fig. 14). Until this time only two wells had been drilled to deep formations within 60 miles of this location. The seismic crews of Imperial had traversed the area and their delicate seismographs recorded data which indicated subsurface structures that appeared to be out of the ordinary. In geological jargon, these are termed "anomalies", and this is what the seismic crew detected in the Leduc area.

As the drilling of Imperial Leduc No. 1 proceeded, methodical well-logging was undertaken, and geologists studied the cores brought up with intense interest and apprehension. Samples were taken at five-foot intervals as against the customary ten-foot ones required by the provincial government. The hole was cored continuously after reaching Lower Cretaceous Viking sandstone at 4,390 feet. After that, intermittent coring was resumed. Some showing of oil and gas appeared on the cores as the Lower Cretaceous formations were penetrated but they proved unproductive. The crew had instructions to drill deep to test for the Devonian formations discovered by California Standard at Princess. In early February, after more than 10 weeks of drilling to a depth of about 5,000 feet, there were showings of high-gravity oil in the drilling mud. Upper Devonian coral reef dolomite, later named Nisku (D-2), had been reached. The crew drilled to 5,066 feet, and on February 3 it was decided to begin a production test. It was estimated that it would take 10 days to find out if the well was a producer. The company took a chance and

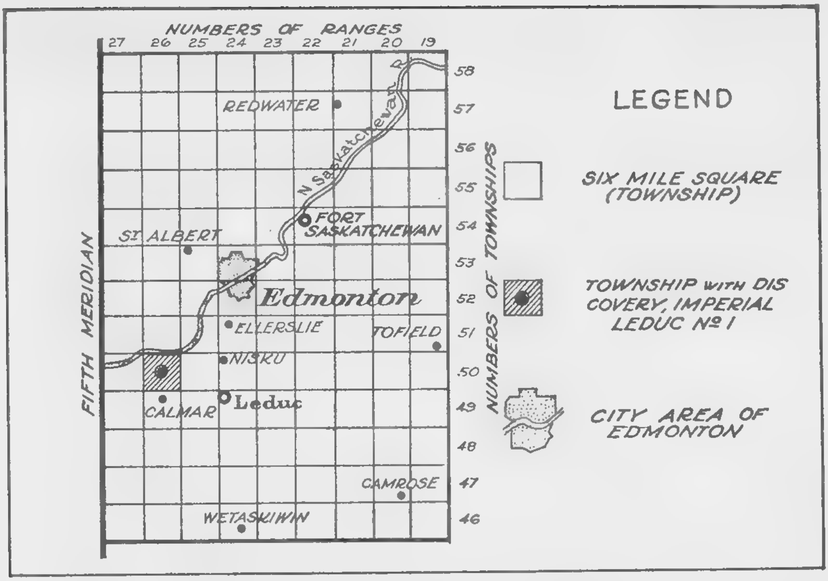


Fig. 14 The Edmonton area, showing its township grid system

Note on the Grid Survey System in Western Canada: The Prairie Provinces of Canada are divided north and south into five areas separated by meridians. The first meridian is in Manitoba, the fourth on the Saskatchewan-Alberta boundary, and the fifth in western Alberta, just west of Edmonton. The area between meridians is divided into RANGES, each six miles wide, running north and south. Each range is cross-divided by township lines which run east and west six miles apart, to form TOWNSHIPS six miles square (36 square miles or 36 sections). The No. 1 township of the Prairie Provinces lies just above the international boundary. The township in which the Imperial Leduc No. 1 was drilled is labelled Township 50, Range 26, west of the Fourth Meridian. In abbreviated form this would be T.50, R.26, W 4th, or even 50-26, W 4. The discovery township lies 50 times 6 or 300 miles north of the international boundary and 26 times 6 or a little more than 150 miles west of the Saskatchewan boundary.

invited government and company officials, journalists and radio reporters to come out to the well site on February 13. A number of Edmontonians and district farmers also came. It was a cold day and many went home before the well came in at four o'clock in the afternoon, but an estimated 500 people remained. One of these was N. E. Tanner, the minister of lands and mines of the Alberta government, who ceremoniously turned a valve to begin the production of oil.

Vernon Hunter, who is now manager of Imperial's producing division in Regina, recently reminisced as follows to the Edmonton *Journal* (February 13, 1957) when he attended the tenth anniversary celebration of Leduc in Edmonton:

"By noon a crowd was gathering. By four o'clock the less hardy had shivered their way back to town, but the faithful saw a beautiful ring of black smoke go floating skywards—a good omen for the oil industry in Western Canada.

"There is a time lag between the time you hit a rock formation bearing oil and the time the well is brought in. As a matter of fact the discovery date of a well is the date it is put on production.

"When we struck oil-bearing rock and figured we really had something at long last, I was asked when the well would come in. I said it would take about 10 days. That's the last time I will ever predict when a well will go on production.

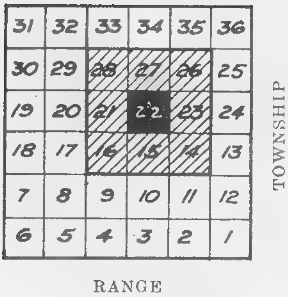
"For I discovered that representatives of the press and radio, as well as other officials, were going to be on hand for the event, so the date was of something more than just academic interest.

"By the morning of February 13—the date set—we hadn't started to swab and that operation sometimes takes days. (Swabbing is a technique for sucking the oil to the surface to start the well flowing.) However, we crossed our fingers and at daylight started in. (At this point, the swabbing unit broke down. However, repairs were made and swabbing continued.)

"Shortly before 4 p.m. the well started to show some signs of life. Then with a roar the well came in, flowing into the sump near the rig. We switched it to the flare line, lit the fire and the most beautiful smoke ring you ever saw went floating skywards."

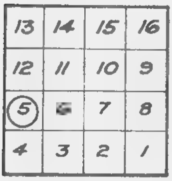
One producing well does not make an oil field, and the company accordingly set another crew to work at once on a "step-out" well, Imperial Leduc No. 2, nearly one and a half miles south of the No. 1 well. The drillers reached the D-2 zone which produced the discovery well at 5,085 feet, but the rock, while indicating the presence of some oil, was too tight to produce, that is, not porous enough to promote the flow of whatever oil there was in it. It seemed as if Imperial had run out of luck again. But there was no looking back and the crew was ordered to keep on drilling. At 5,370 feet a third Devonian zone of dolomite, Leduc D-3, was reached. It produced a flow of 39° API crude oil. The well was completed on May 10 and brought in as a producer on May 21.

A second step-out well, located about one and three quarters of a mile northeast of the No. 1 well, started in March, found oil in the D-3 zone also and came in as a producer on May 21, the same day as the No. 2 well. A third step-out well, spudded in about a mile southeast of the No. 1 well in late March, came in as a D-3 producer on June 7. It was becoming increasingly clear that there was an oil field in the making. Four offset wells were drilled close to the discovery and step-out wells to protect the rights of adjoining landowners. By the end of the year, Imperial



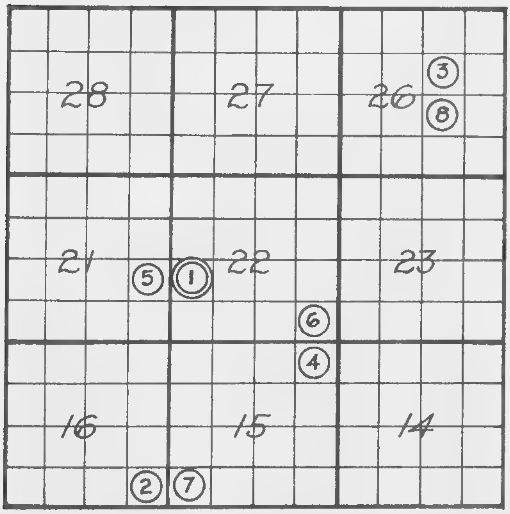
The 36 Sections in a township are each given a number arranged as in the diagram. The shaded Section 22 is equivalent to the square in B below and the cross-hatched nine sections correspond to the square in C below.

A. DIVISION OF A TOWNSHIP INTO SECTIONS



Each section contains 640 acres and is divided into 16 legal subdivisions each containing 40 acres. The Imperial Leduc No. 1 well is located in L.S.D. 5, Section 22, Township 50, Range 26, W 4th.

B. DIVISION OF A SECTION INTO LEGAL SUBDIVISIONS (L.S.D.)



The first eight Imperial Leduc wells were drilled in Sections 15, 16, 21, 22 and 26. The circled figures indicate the numbers of the wells drilled with a double circle for the No. 1 well. The other figures are numbers of Sections.

C. LOCATIONS OF THE FIRST EIGHT IMPERIAL LEDUC WELLS IN T.50, R.26, W 4TH

Fig. 15 The first eight wells drilled in the Leduc field, located by the grid system

drillers had completed 12 D-2 producing wells and 11 D-3 wells. It was a dual zone field, with one pool overlying another.

Other companies, some newly formed, acquired land in the area and shifted drilling rigs from areas in Alberta to Leduc. Scattered pieces of acreage within the Imperial reservation went to the highest or quickest bidders. By and large, these companies were less successful than Imperial in their drilling, partly because they were able to acquire only small parcels of land, scattered here and there in the area. During the year they completed 15 wells of which six were abandoned.

The search for oil also spread to other parts of the Edmonton region as many companies got into the act. The number of exploratory wells drilled increased considerably as the Leduc discovery stimulated exploration. "Wildcat" drilling in Alberta produced seven oil and six gas producers out of 71 holes drilled for a "batting average" of .182 as against the three oil and five gas producers out of 54 attempts and an average of .148 in 1946. The average for 1947, however, was far more significant than its numerical size indicates for among the "hits" was the grand-slam home run produced by Imperial's wildcat No. 134.

The Development of the Leduc Field

Once a successful well has been completed it becomes a matter of establishing the limits of the pool and of detecting neighbouring pools. Step-out wells are drilled in the vicinity of the discovery well, and if they become producers, offset wells are also drilled very close to them. This process is usually termed development drilling. Once a number of step-out wells have come in to establish the existence of a pool of significant extent, outpost wells may be drilled miles away in various directions to try to determine the extent of the pool and to find out if there are adjacent pools.

The pattern and rate of development depend in large degree upon the number of companies in the field and the size and distribution of their holdings of subsurface rights. In the Leduc area, Imperial Oil had obtained leases and reservations covering large areas by payments to freeholders and to the provincial government. Consequently, it was able to plan and carry out an orderly pattern of development drilling, including outpost wildcats. Other companies assisted as they acquired the acreage left, and they did much to explore the fringes of the field outside the main Imperial leases and reservations, where there was more acreage available than near the discovery well. With participation by Imperial and a number of smaller companies, drilling in the Leduc field proceeded rapidly, though not as fast as might have been the case if there had not been a

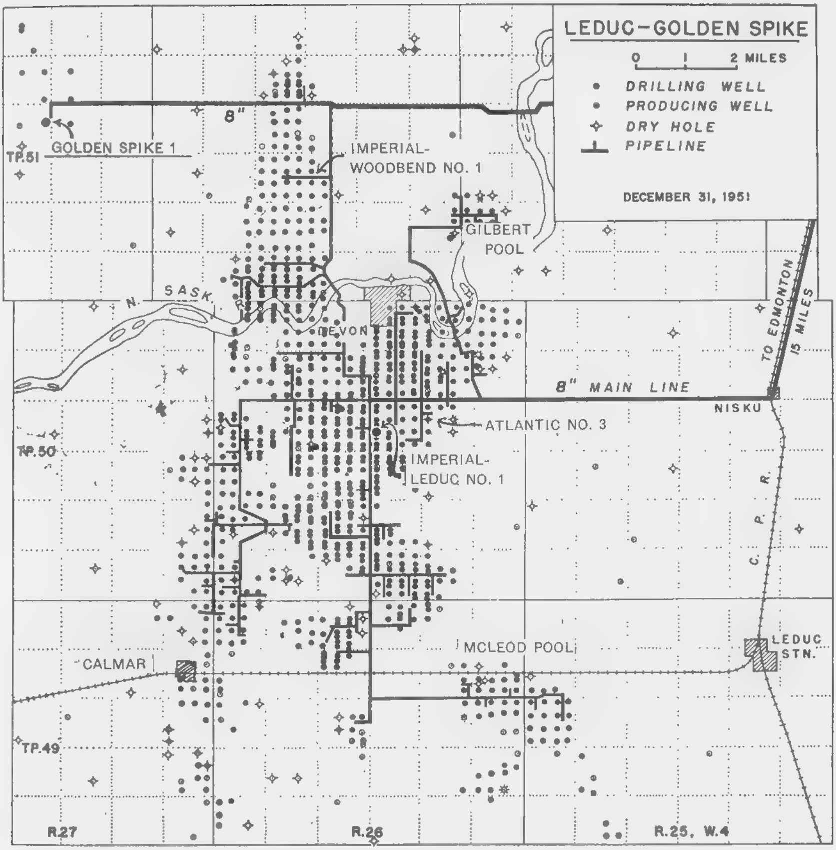


Fig. 16 The Leduc-Woodbend and Golden Spike fields in 1951

shortage of drilling rigs, pipe, casing and other equipment. Furthermore, well-spacing was limited by the Alberta Conservation Board to one well per 40 acres, that is, one for each legal subdivision in a section or square mile of land.

Beside acquiring petroleum rights in the discovery township, Imperial Oil had obtained a reservation or "exploration permit" from the provincial government covering most of Township 51, Range 26, in the Woodbend area north of the North Saskatchewan River and the discovery township. Here the company spudded in a wildcat, the Imperial Woodbend No. 1, on October 14, 1947 (see fig. 16). The well was completed on January 18 at a depth of 5,340 feet and became a D-3 producer. This was followed up by the drilling of step-out and offset wells which gradually established the northern part of what is now called the Leduc-Woodbend field. Other companies drilled on the western, south-

ern and eastern fringes and, year by year, the surface contours of the pool became wider and longer.

In the course of 1948, a total of 147 wells were drilled in the Leduc field, nearly two fifths of the Alberta total. Of these 131 became oil producers, five discovered gas and eleven were dry. In August, 1948, crude oil with 39° API gravity was discovered in Lower Cretaceous sandstone at a depth of about 4,200 feet by Continental Oil of Canada.

One event provided drama during the year. In January, 1948, the Canadian Atlantic Oil Company began drilling a well, the Atlantic No. 3, one mile northeast of the Imperial discovery well. The drillers lost control on March 8 and the well "blew out", gushing oil and gas to the surface and creating numerous craters. Stuffing the well from the surface with tons of cement, feathers, sawdust, mud and a miscellany of materials proved futile. Eventually, by the "directional" drilling of two relief wells, the wild Atlantic was brought under control on September 9, shortly after it caught on fire (see fig. 17).

During much of the period many of the wells of the field were closed down to enable the pipe line to transport the oil in the craters to Nisku. The well set a production record with an output of an estimated 1,250,000 barrels of oil in a period of six months, about one quarter of the output of the whole Leduc field in 1948. Probably no event gave the oil development in Alberta more widespread publicity than the blowout of the Atlantic No. 3.

An important extension of the D-2 producing area was made during 1949 when the "McLeod pool" was found. It was named after Jack McLeod, president of Leduc-Calmar Oils, a small Alberta independent company, who spudded in a wildcat several miles southeast of the main proven area despite adverse geological advice. The drilling rig was wrecked by a high wind before drilling was completed. Another well was begun in the northern part of the same 40-acre legal subdivision; it turned out to be a dry hole. The rig was then moved to the southern part of the 40-acre plot and oil was found. Further drilling in the area resulted in a substantial addition to proven D-2 acreage. The incident is indicative of the large element of chance in oil-finding and the diligent daring of some operators.

Development drilling in the field continued apace and reached a peak in 1951 when more than 300 wells were completed and almost 1½ million feet of hole were drilled. The productive D-3 pool was developed more rapidly than the D-2, but as the former became drilled out, operators turned increasingly to extending the latter which ultimately turned out to be larger in area than the D-3 pool, although much less rewarding in its yield of oil. Drilling in the Leduc field declined rapidly after 1952 and practically ceased by 1955 (see fig. 18).

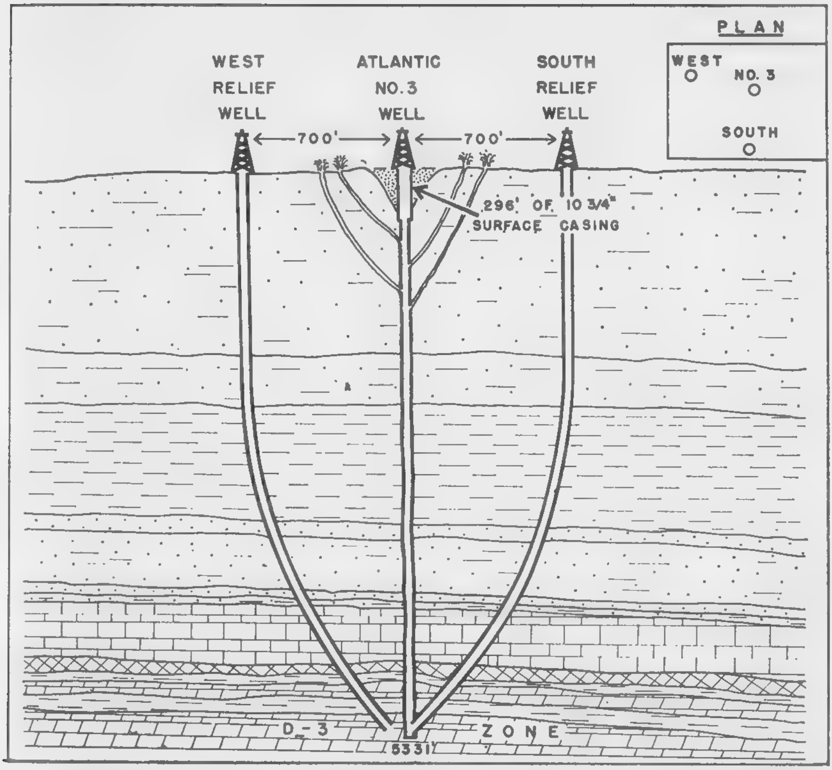


Fig. 17 Atlantic No. 3 well killed by two relief wells, Leduc, Alberta

The number of wells capable of oil production rose rapidly as drilling activity proceeded at a high rate and as more than nine out of the ten wells drilled turned out to be producers. Crude oil production increased so much that market outlets for all that could be produced could not be found immediately, and the rate of production per well had to be curtailed materially by 1950. The new field took the crude-oil production leadership away from Turner Valley in 1948, the second year of its life, with an output of 4.7 million barrels. It did not retain the title as Alberta's, and Canada's, prime oil field for more than two years, for by 1950 a new horse, Redwater, had hit its stride and nosed out Leduc-Woodbend. The following table indicates the crude oil production of the three fields that showed during the first five years of the Leduc boom as well as that of the "also-rans".

All this oil created a marketing problem, even on the oil-starved Canadian prairies. Refinery capacity was limited and the nearest refineries were at Calgary. This raised immediate transportation problems. Tank trucks were used in 1947 to haul the crude oil to hastily constructed tank-

car loading facilities at Leduc. From there the oil went to Calgary refineries which by then were at the stage of importing crude from the United States. From Calgary the refined products were moved by rail and truck throughout Alberta.

Crude Oil Production in Western Canada, 1947-51

In millions of barrels

Year	Turner Valley	Leduc-Woodbend	Redwater	Other Alberta Fields	Total Alberta	Total Western Canada
1947	5.0	0.4		1.0	6.4	6.9
1948	4.4	4.7		1.4	10.5	11.3
1949	3.8	9.7	4.8	1.5	19.8	20.5
1950	3.3	10.6	10.7	2.5	27.1	28.2
1951	3.0	13.7	23.2	6.0	45.9	47.2

Once Imperial Leduc No. 4 came in, Imperial Oil began to plan a field gathering system of pipe lines, flow stations (also called production batteries), and a trunk pipe line to the railway eight miles away. Pipe was very difficult to obtain during the immediate postwar period and in the intensive search for a supply of it, someone found enough pipe in North Carolina which was in the process of being disinterred. This particular eight-inch pipe had originally carried crude oil in a West Texas field and had been moved during the war as an emergency measure to be relaid between Greensboro, North Carolina, to Richmond, Virginia, to carry petroleum products. It was much-travelled by the time it reached Alberta. An eight-mile line was completed from the discovery area of the Leduc field to Nisku by late October. It began operations on November 3, 1947, when the Alberta government's expert on pipe lines, G. M. Blackstock, Chairman of the Board of Public Utilities Commissioners of Alberta, came to Nisku from Edmonton to fill the first tank car. A tank farm, consisting of three tanks with a combined capacity of 20,000 barrels, was also constructed during the year. The pipe line was capable of transporting 30,000 barrels per day and proved adequate to carry all the crude of the field during the first few years, except during the "wild well" emergency of 1948. The new pipe-line company began at once to plan and to construct a pipe-line system to carry oil from the wells of all producers desiring service to the trunk line.

The open-flow potentials of the D-2 wells in the Leduc-Woodbend field varied from 800 to 1,000 barrels per day and those of the D-3 wells from 1,000 to 4,000 barrels per day. Markets were not available for such

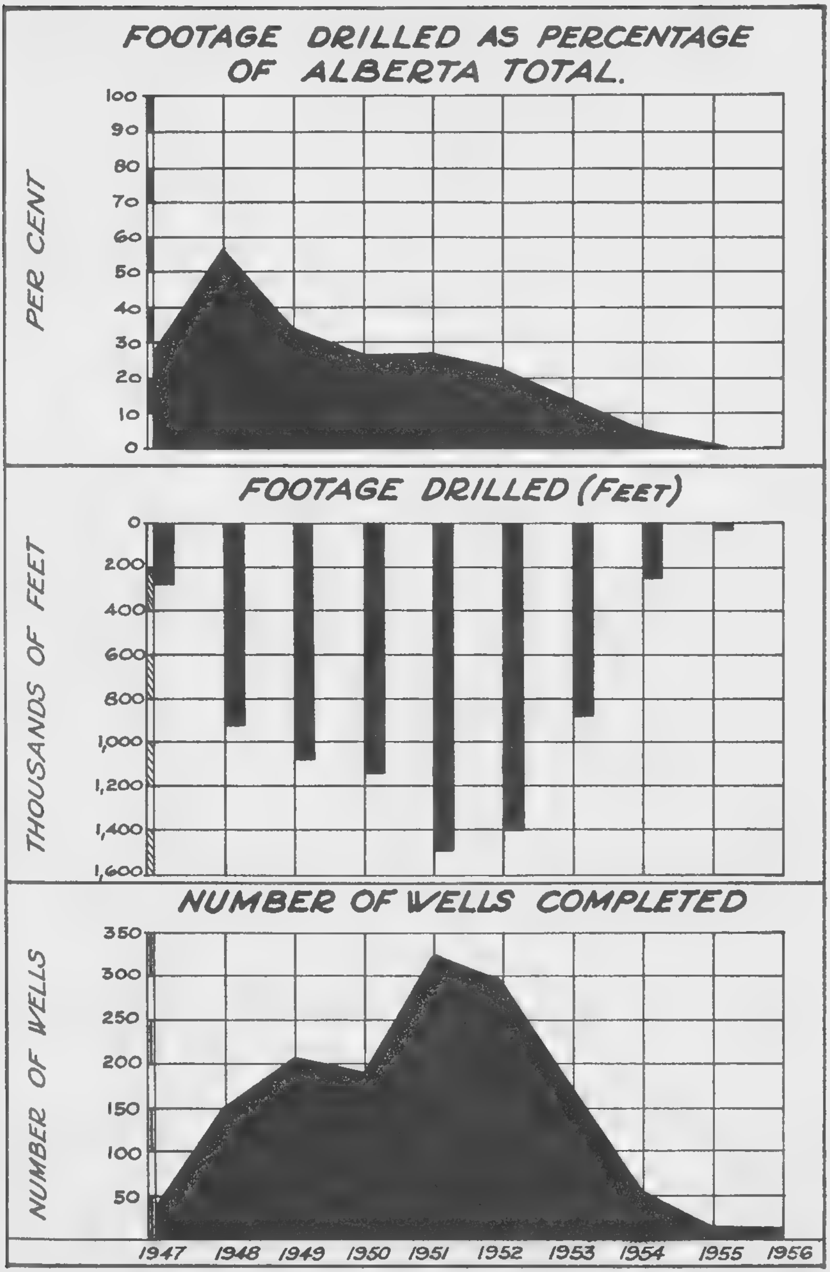


Fig. 18 Drilling activity in the Leduc-Woodbend Field, 1947-56
Source: PNGCB

"flush" production. Furthermore, it is not good engineering practice to let wells produce uncontrolled; to do so reduces the basic water and gas drives seriously, to such a point that in a relatively short time the oil has to be coaxed out of the ground by various artificial means such as re-pressuring with injected gas or water or by pumping. For ultimate maximum recovery it is necessary to control the flow, and the engineers of Imperial Oil set the production of the company's wells at from 100 to 150 barrels per day. In December, 1947, the Conservation Board declared the Leduc-Woodbend field an "Administrative Area", subject to its conservation regulations, and it issued an order restricting production to 100 barrels and 150 barrels per day for D-2 and D-3 wells respectively of all operators.

Table I

Production of Hydrocarbons in the Leduc-Woodbend Field, 1947-56

Year	Wells Capable of Oil Production at end of year	Crude Oil Production Total 000's of barrels	Crude Oil Production Approx. Average per Well 000's of barrels	Natural Gas Production 000's of mcf	Propane Production 000's of barrels	Butane Production 000's of barrels	Natural Gasoline (Pentane) Production 000's of barrels
1947	28	372	13	328			
1948	175	4,657	27	2,346			
1949	363	9,689	27	5,320			
1950	519	10,589	20	6,120	50	34	15
1951	800	13,743	17	8,370	143	85	44
1952	1,082	17,845	16	11,470	230	140	67
1953	1,243	21,360	17	14,650	287	198	82
1954	1,278	20,561	16	15,050	314	220	94
1955	1,275	20,421	16	15,993	316	245	117
1956	1,255	21,098	17	17,042	377	290	142

Source: PNGCB.

By 1949 crude oil from Leduc, the new Redwater field and other fields was moving to refineries throughout Alberta and Saskatchewan, mainly by rail and truck. Imperial Oil was giving serious consideration to the construction of a pipe line from Leduc to Regina. Railway rates were too high to permit the economical movement of crude oil to Manitoba which had little refining capacity and obtained most of its petroleum products from eastern Canadian and Saskatchewan refineries by rail.

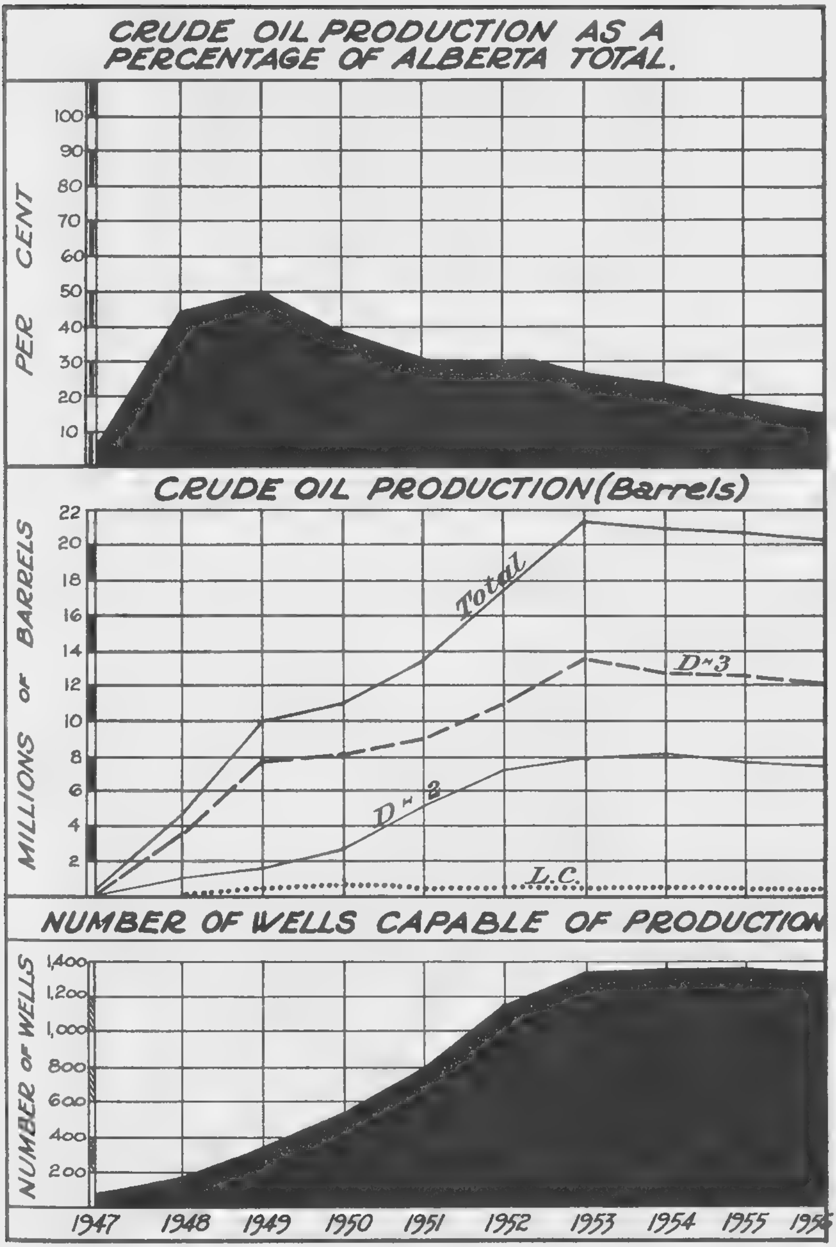


Fig. 19 Production and number of producing wells in the Leduc-Woodbend Field, 1947-56   Source: PNGCB

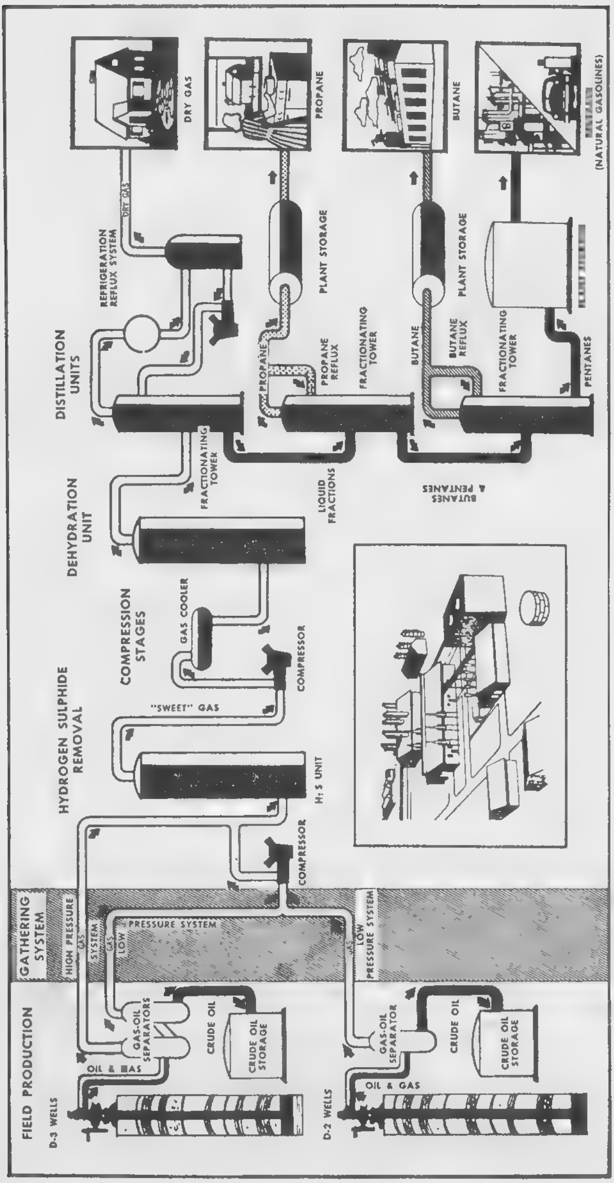


Fig. 20 Leduc Gas Conservation Plant. Diagram showing the flow of natural gas from the well to the consumer.

The failure of markets to expand rapidly enough checked production, and even drilling, in the Leduc-Woodbend field in 1949-50 (see figs. 18 and 19). During the early 1950's the development of the field approached completion. It attained a peak production of 21.4 million barrels in 1953; there were slight annual declines in 1954 and 1955 followed by an increase in 1956. The number of wells capable of oil production reached a maximum of 1,278 in 1954 and since then the number has fallen somewhat (see Table I, p. 76).

The Leduc-Woodbend field has been a significant producer of natural gas from the beginning because much gas is produced with the oil. By 1949 it became Alberta's third largest gas field after Turner Valley and Viking-Kinsella, a distinction which it retained until 1956 when its output was exceeded by both the Pembina and the Jumping Pound fields.

There was little market for the gas during the first three years of the field and much of it had to be flared. In May, 1950, Imperial Oil completed a conservation plant at Devon at a cost of about $7 million. It was capable of processing up to 35 million cubic feet of gas per day (see fig. 20). The gas processed by this plant is separated from the oil at the production batteries and transported to the plant by a system of gathering lines. Four distinctly different products are made from the field gas. The first is a "dry" natural gas with a high methane content which is sold to Northwestern Utilities for space-heating purposes in Edmonton. The second is propane, a hydrocarbon which has increasingly come to be used as a fuel in the small towns and on the farms of the prairies and as a power fuel in trucks and buses. The third is butane which is a raw material for the petrochemical plants constructed in Edmonton after 1951. The fourth consists of pentanes, that is, natural gasolines, which are sold to the Edmonton oil refineries to be used in the blending of motor gasolines. Table I shows the output of these four products since 1950.

The Development of Oil Towns in the Field

The provision of housing for oil workers became a pressing problem during 1947 and workers crowded into Leduc, about 12 miles from the discovery well by road, and into Edmonton, nearly 20 miles distant by road, to obtain rooms, suites, houses or space for their trailers. Calmar, about 12 miles away, became crowded as the southern part of the field was developed. Requested by production men to find a trailer camp-site in the field, Imperial Oil decided to establish a new town near the discovery area instead of just space for a collection of trailers and shacks. While such temporary communities were common

in oil fields, they were far from being ideal places in which to live for they provided few municipal services, schools and recreation facilities. Poor sanitation made for hazardous health conditions. Much of the population growth that accrued to Leduc and Calmar was of this kind, and neither of these two places was fully served by water and sewage systems. It took provincial government financial assistance to provide these towns with adequate municipal services and schools in subsequent years. Commuting to the oil-field sites was often difficult because of the poor state of the roads; the provision of good roads came also in subsequent years as oil companies, the rural municipalities and the provincial government negotiated with each other to divide the financial responsibility equitably.

In the meantime, Imperial Oil obtained a quarter-section of land on the southern bank of the North Saskatchewan River, about two miles north of the discovery well, and announced its intention to develop a town to be called Devon. The Department of Municipal Affairs of the Government of Alberta provided assistance in planning the town through its town planning commission. Fig. 21 shows the original proposed plan for the townsite, and it was largely put into execution. Imperial Oil decided to put its Leduc-Woodbend production offices in the town and to build its gas conservation plant on an adjoining quarter-section. The company also installed water, sewer and gas systems in the town and set up a subsidiary, Devon Estates Limited, to handle real estate sales and guarantee mortgages on houses and lots. Arrangements were made to permit oil workers to purchase houses with a down-payment as low as $200. The Central Mortgage and Housing Corporation, a federal government agency, assisted in financing mortgages and in development planning. Last, but not least, was the provision made for drilling oil wells on the four legal subdivisions of the town.

Four wells were subsequently drilled inside the town by Imperial Oil and they came in as producers. Two of them are "twin wells" drilled on the same 40-acre subdivision, a common occurrence in the field since there are two pools under the same surface over much of the area, namely, the D-2 and D-3.

Before the winter of 1947-48 a contracting firm, Engineered Buildings Limited, had set up 25 prefabricated houses, and during the winter the Imperial Oil production office and the quarters for single men were constructed. Today there are several hundred homes in Devon, a sizeable business area and a number of oil company and oil service contracting offices and supply depots. Unlike most Western Canadian small towns it has a swimming pool and like most of them it has skating and curling rinks, deemed essential by prairie residents who think they breed the best hockey players and curlers in the world. There is also a nine-

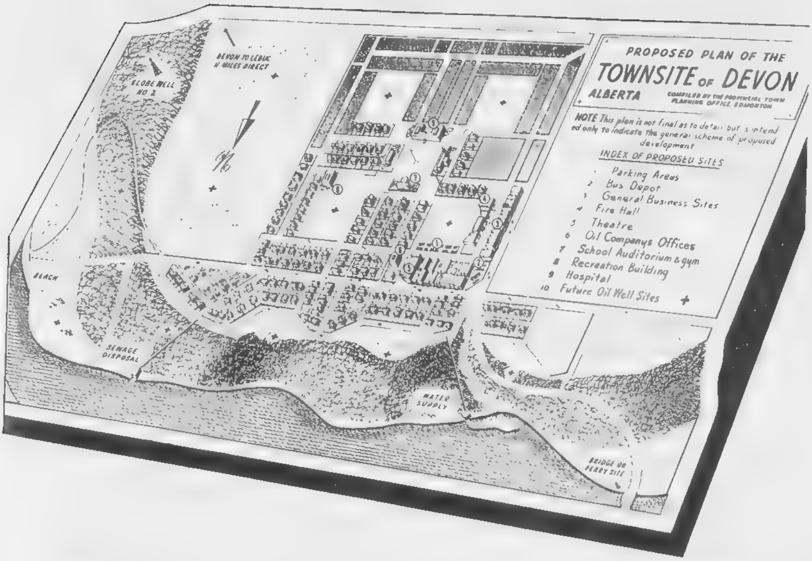


Fig. 21 Artist's conception of how Devon, on the North Saskatchewan River, would look

hole golf course, although most western Canadians are indifferent golfers because of the short season. There is the usual school with an auditorium. The town presents quite a contrast to most other prairie towns in its new, streamlined appearance and in its lack of a railway and grain elevators. It is an oil town, originally designed to provide homes for drillers, but which now serves as the centre from which oil production workers and natural gas plant employees operate.

The community was incorporated as a village on January 1, 1950, and almost immediately after as a town on March 1 of the same year. One of the first residents, George Thompson, was elected mayor and he was also named official trustee by the Alberta Department of Education when a special school district was formed on June 1, 1950. The town applied to the provincial government for the merging of municipal and school government functions under the control of one council, in line with the government's experiments in some rural areas where so-called "counties" were set up and school boards abolished with their powers transferred to a "county council". This application was turned down, but Devon residents, determined to keep their local government as simple as possible, elected five of the seven-member town council to the five-member school board when a self-governing school district was set up. The council then obtained a loan from the provincial government, which had just set up a fund to assist towns and villages to pro-

vide utilities, to purchase for $300,000 the sewer, water and gas system constructed by Imperial Oil at a cost of nearly one million dollars.

The population of Leduc rose rapidly during the early years of the field and before Devon was completed; in 1951 its population was double that of 1946. The population of the town has not risen markedly since. Calmar, which probably had about 200 people in 1946, attained a population of nearly 1,000 by 1951 and became incorporated as a village while the southern part of the field underwent development. There was a considerable population decline at the cessation of field development. The population of Devon rose greatly between 1951 and 1956, and the following table indicates the population changes of the three centres in the Leduc-Woodbend field since 1946:

	1946	1951	1956
Calmar	200*	944	716
Devon		842	1,423
Leduc	920	1,842	1,969
Total	1,120	3,628	4,108

Source: DBS, census data.

*Calmar was unincorporated in 1946 and hence separate census data are not available. The figure is estimated.

Oil towns undergo rapid expansion during the drilling and development stage, and this expansion is arrested as the population stage becomes dominant. The ten-year effect in the Leduc-Woodbend field has been almost a quadrupling of the population of the three towns in it. Ultimately, decline can be looked for as production in the field falls. Oil towns undergo a cycle of development. The working force in the petroleum industry is more than ordinarily mobile; much of it shifts from field to field as new discoveries are made and a core of production, transportation and natural gas plant workers are left behind. Careful planning by oil companies, the local authorities and the provincial government is desirable to avoid overbuilding and overexpansion of local debt during the expansionary stage. Much of the temporary population of Leduc and Calmar in the late forties lived in mobile trailers, and there is no particular legacy of empty residences and business buildings. Both acquired water and sewer systems, largely financed by provincial government loans made possible by revenues from petroleum development. Both serve the agricultural communities around them as well as the oil industry. Devon has reached its peak population and is likely to experience slow decline as the production of the field falls over the next 20-30

years; this decline, however, was taken into account in its planning and in many of the investment decisions made. New factors can reverse the trend for no one can predict with certainty the fate of a town years hence. In 1946, few people thought Leduc would attain a population of 1,000; the wildcatters for oil came along and now it has nearly 2,000 people.

The Significance of Leduc

The importance of the Leduc discovery can hardly be exaggerated. It came at a time when oil consumption was rising and oil production was falling in Western Canada. The field provided large quantities of high-quality crude from the first year of its life. It was located in an accessible area, close to a major city which provided a ready market for the crude oil.

More significantly, the discovery stimulated a variety of ventures by investors in Alberta. It is not every day that a field with more than 200 million barrels of recoverable crude oil is discovered; indeed, such discoveries have become a rarity in the United States. There was an immediate rush by oil companies to acquire petroleum acreage in the Alberta Devonian "fairway" which runs from the northwest through the eastern Peace River region, through the Edmonton area, and into southwestern Saskatchewan. The "fairway" is about 1,000 miles long and averages 200 miles in width with Edmonton close to the centre of it. During the years following 1947 many Devonian reef limestone fields, so difficult to discover because they give practically no surface clues to indicate their existence, have been discovered in the fairway. Many other fields with different structures have also been found, both inside and outside the fairway. The annual investment of oil companies on land acquisition, exploration, development and production in Alberta rose rapidly from about $12 million in 1946 to almost $400 million in 1956.

Edmonton became a refining and petrochemical centre and the main base of operations for oil-industry contractors. Many other centres have also increased in size and have been transformed by the oil industry. A large investment in other industries and housing has been induced by the oil boom. Regional government expenditures have risen, financed to a very large extent by revenues from the oil industry. But all this is a story which we shall develop gradually.

8

Redwater

Shortly after the Atlantic well was brought under control, and almost 20 months after the Leduc discovery, Imperial Oil, which was carrying out an extensive wildcat drilling program, brought in Imperial Redwater No. 1, some 40 miles northeast of Edmonton. Redwater was to become an even greater field than the Leduc-Woodbend and its discovery was followed by a regular spate of discoveries in the Edmonton region of smaller, but very important, fields in Devonian formations.

The Nature of the Redwater Area

The Redwater field runs in a southeasterly direction for almost 20 miles and is three to four miles wide (see fig. 22). The region is a mixed-farming community with land varying in quality from good to poor. The topography is rolling and sometimes rough; fields and wooded areas and even muskeg give variety to the scenery. Nearly all the subsurface rights were held by the provincial government in 1948. Oil made the area prosperous. The obscure little hamlet of Redwater, with about 200 people, became a town with a couple of thousand people and its name had become a household word in Canada by 1949.

The Discovery Well

An Imperial Oil rig spudded in a well on L.S.D. 1 of Section 32, Township 57, Range 21, West of the Fourth Meridian, about one mile northeast of Redwater, on July 23, 1948. Viking sandstone was reached at 1,940 feet and tests revealed the presence of gas. The first Devonian (D-1) limestone was reached at 2,615 feet but it contained nothing but water. The second Devonian (D-2), beginning at

2,856 feet, also produced only water. The drill bit began piercing green shale at 2,990 feet and met the third Devonian (D-3) at 3,105 feet. Tests revealed oil with 34° API gravity.

Few reservoir rocks have uniform porosity and permeability and there are often "tight" areas interspersed among the porous. The former reduce permeability. In the sandstone and limestone formations so common in Alberta, areas of cemented sand grains or "tight" limestone are frequently present. To increase the permeability of a formation, and hence the production from a well, shooting or acidizing may be employed to open up the pores to make oil and gas flow freely. If the formation is sandstone, shooting is resorted to and if it is limestone, it is usually acidized.

Shooting consists of lowering solid nitroglycerine in tin torpedoes into the holes and detonating them by an electrical device. Acidizing consists of pumping a special hydrochloric (muriatic) acid into the lime or dolomite formation. The acid dissolves a portion of it by chemical

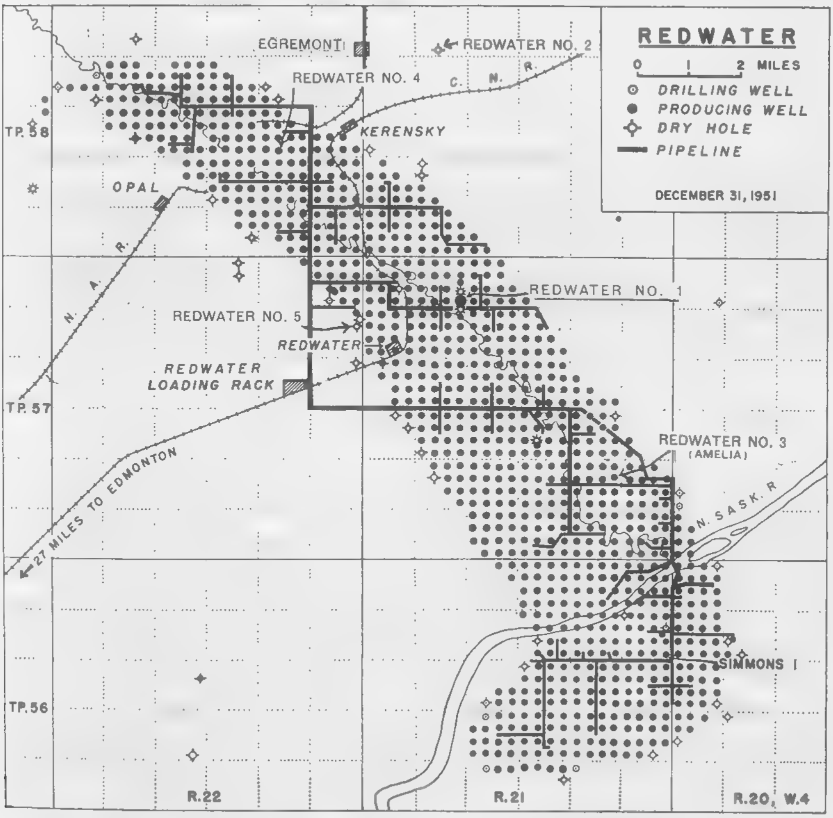


Fig. 22 The Redwater Field, 1951

reaction, thus enlarging the pores and fissures. Shooting and acidizing have often made commercial producers out of wells which otherwise would have been dry holes. Perforating, shooting, fracturing and acidizing are done by contractors who specialize in these intricate operations.

The Redwater discovery well was treated with 18,700 gallons of acid and was then swabbed. Swabbing involves running a "swab" up and down through the tubing to bring up mud, water and other matter to permit the oil to flow freely. The well was brought in to produce, on

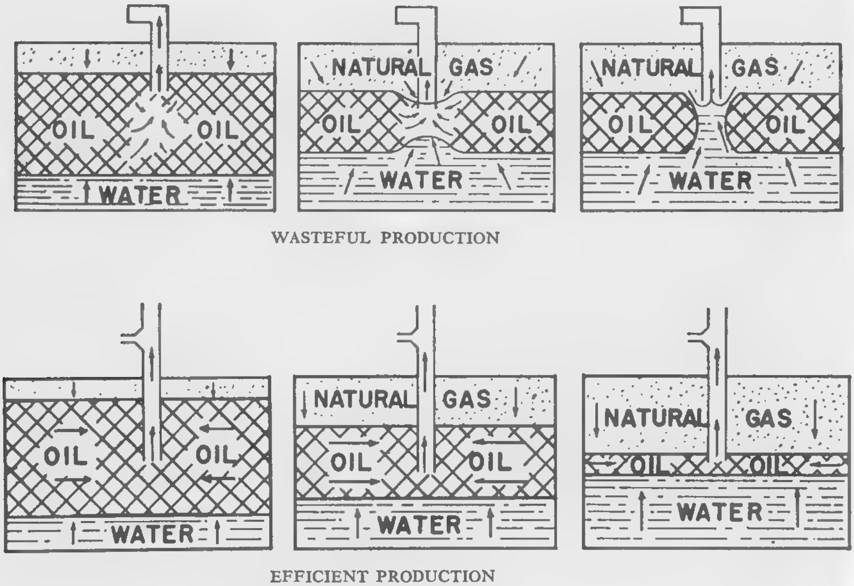


Fig. 23 Wasteful and efficient production

open flow, 75 barrels of water-free 35° API crude oil per hour. Open flow is also called "flush" production which means that the basic reservoir drives are permitted to push oil to the surface as fast as they can without restriction by chokes or other means. Usually a well is not permitted to produce with open flow any longer than is necessary for engineers to test the reservoir pressures. To let a well flow unrestricted will exhaust the reservoir pressures in an unduly short time and hasten the need for pumping. It is also very likely to reduce the amount of oil ultimately recovered. Furthermore, it is very seldom that a made-to-order market is available for "flush" production of a field. Fig. 23 illustrates the principles involved in conservation practice.

The Development of the Redwater Field

Before the end of 1948 Imperial Oil began to drill four additional wells in the Redwater area. Three of these were on Crown (provincial government) reservations. Government regulations required that each well must initially be located at least four and a half miles from the discovery well. Imperial Redwater No. 2 was accordingly drilled about five miles north of the discovery well. It went to 4,060 feet in a vain search for the productive D-3 zone and was abandoned on November 3. The third well, the Imperial Amelia No. 1, was drilled about four and a half miles southeast of the No. 1 well (see fig. 22). It was completed as a D-3 producer at 3,303 feet with an open flow of 1,935 barrels per day on January 3, 1949. A fourth well, the Imperial Egremont No. 1, was drilled four and a half miles northwest of the first well, near the village of Egremont. It reached productive D-3 limestone on November 10, at 3,235 feet, but it was drilled down to 4,476 feet to test formations below the D-3. It was then "plugged back" more than 1,000 feet to the productive formation and completed as a producer on December 6, 1948. Imperial Redwater No. 5 was drilled about two and a half miles southwest of the No. 1 well on land where the mineral rights were privately owned. It was completed on January 11, 1949, at 3,314 feet; very little oil was found and the well was abandoned. Before the end of 1948, then, Imperial Oil had brought in two producers, the total for the field, and was drilling three wells, two of which became dry holes while the other came in as a producer in early 1949. The three producing wells were located on a 10-mile line running from the northwest to the southeast. This was to be the direction or "trend" of the ultimate 20-mile-long field.

Some drilling had been done in the Redwater area before Imperial Oil brought in its No. 1 well. In 1897-99 the Dominion government had drilled a dry hole at Victoria about 30 miles east of the Redwater discovery. Clonmel Petroleums had drilled another dry hole to 3,181 feet without reaching Devonian formations in 1942 at a location 12 miles southeast of the Imperial No. 1 well and about eight miles from the Imperial Amelia well. In 1946 the Anglo-Canadian, Home, Calgary and Edmonton team reached Devonian limestone without finding oil. Across the North Saskatchewan River, in six townships east of Redwater leased from the provincial government under an exploration permit of the same kind that Imperial had taken out in the Redwater area, the Amerada Corporation drilled seven dry holes during the latter half of 1948. In 1949 the company obtained the lease on Section 16 in the Redwater discovery township from the Alberta government with a bid of $3,223,230. It drilled

its full quota of 16 wells on these expensive 640 acres and they all came in as producers. This meant a land cost of about $200,000 per well plus royalties on production payable to the government.

At the end of 1948, the now dual Canadian Oil and Home team and Redwater Petroleums had four drilling rigs, supplementing those of Imperial. The former brought in all its three wells begun in 1948 as producers in January, 1949, while the Redwater Petroleums well had to be abandoned in February, 1949, after being drilled to 4,066 feet. The company, which had been incorporated in Ontario in 1948, tried once more during 1949 but sunk most of the rest of its money into another dry hole. Its fate is typical of many small companies which cannot afford to bid on highly prospective acreage and which have only enough money left, after obtaining less favourable acreage, to drill one or two wells.

On November 10, 1948, the Alberta government held its first "auction sale" of Crown reservation land not taken up by Imperial Oil in the Redwater area. At such a sale companies bid by sealed tender for the right to lease certain parcels of land. Canadian Oil Companies "bought" a quarter-section for $351,000, Home Oil another for $302,000 and Pacific Petroleums and associates 160 acres for $283,000. During 1949 Imperial Oil began to select the mineral rights it wished to convert from exploration reservation to lease in accordance with provincial government regulations. These specified that within a certain time after finding oil any company could convert to lease up to 50 per cent of any township in the reservation. A solid block of nine sections may be retained as a lease, but the other nine must be scattered in checker-board fashion within the township. This was a new regulation; it was not in effect when, for example, Imperial Oil obtained a reservation in Woodbend. As Imperial made its choices in Redwater of what to retain and what to return to the Crown, large tracts of land became available to the provincial government, and the greatest land play in Alberta oil history up to the time began. The government held eight auctions during 1949 and sold the leases on 7,028 acres in Redwater for $19 million, about $2,700 per acre. One quarter-section sold for as much as $919,000, more than $5,700 per acre. In addition to companies named previously, British American, Hudson's Bay, Canadian Gulf, Dalhousie, Dome, Ohio Oil, Sunray, Calvan, Princess, Atlantic, Royalite, Texaco and others bought acreage.

A notable acreage position in the Redwater area was held by two private companies—Western Minerals Ltd. who owned the mineral rights, and Western Leaseholds Ltd., who held the lease rights on this freehold land. Both companies were controlled by a Calgary lawyer, Eric L. Harvie.

Originally this large acreage spread derived from the early railway land grants covering a million acres in Alberta between Townships 50 and 60 and between Range 4, West of the Fourth Meridian, and Range 7, West of

the Fifth Meridian. The railways formed land settlement companies, which then sold the surface rights to settler farmers, reserving the minerals. However, it was not clear whether the railway companies had reserved the mineral rights in their original transfer to the land settlement companies, and in the early 1920's it was agreed that the railway companies and the land companies would each take 500,000 acres on a checkerboard pattern.

Mr. Harvie, in the course of his law practice, had become familiar with these early transactions, and when the settlement company lands came on the market in 1943 he, with a small group, acquired 500,000 acres of mineral rights through Western Minerals and Western Leaseholds. Prior to Leduc, these companies actively worked on the coal, salt, sand and gravel possibilities underlying these lands, with little weight then being placed on the oil possibilities.

The two companies held three-quarter section parcels within a mile of the Leduc discovery and even more acreage close to the Redwater discovery. Immediately following the Leduc discovery, lease arrangements were made on some of these lands with Imperial Oil and also with an American group—the Barnsdall, Honolulu, Seaboard and Union of California team. However, Western Leaseholds retained and developed a large part of the Redwater properties and by 1955 it was a large independent producing company, with properties throughout Alberta, Saskatchewan and Manitoba.

This success story illustrates why men venture into the risky oil business.

In 1955 a Belgian-controlled company, Canadian Petrofina Limited which was incorporated in Canada in 1953 and immediately established refining and marketing facilities in the Montreal area, purchased a 96 per cent interest in Western Leaseholds as part of its program of making itself an integrated company.

The land play and provincial government auction sales continued in 1950 in Redwater; the details are deferred to a subsequent chapter. By the end of 1949, 19 companies or groups of companies were active in the field and more came in during 1950. Twelve companies had completed 296 producing wells of which Imperial accounted for nearly 30 per cent and Western Leaseholds for almost 20 per cent.

With relatively shallow drilling depths the Redwater field was developed so rapidly that it took production leadership away from the Leduc-Woodbend as early as 1950 with an output of 10.7 million barrels as against 10.6 million barrels for the pioneer field. Yet production was limited by the lack of markets in that year. With the completion of the Interprovincial Pipe Line to Superior, Wisconsin, in December, 1950, production rose to more than 23 million barrels in 1951, after which there

was little increase as market limitations made themselves felt again. However, production was stepped up considerably in 1955 as market outlets expanded (see Table II).

Table II

Production of Hydrocarbons in the Redwater Field, 1948-1956

Year	Number of Oil Wells Capable of Production	Crude Oil Production 000's Bbls. Total	Crude Oil Production 000's Bbls. Avge. per Well	Natural Gas 000's mcf	Natural Gasoline 000's Bbls.	Propane 000's Bbls.	Butane 000's Bbls.	Sulphur Short Tons*
1948	2	37	18	6				
1949	278	4,793	17	671				
1950	733	10,746	15	1,630				
1951	898	23,178	26	3,652				
1952	926	23,976	26	3,318				
1953	926	23,282	25	3,877				
1954	922	24,896	27	4,209				
1955	907	28,507	32	5,181				
1956	901	28,182	32	4,847	7	13	14	152

Source: PNGCB.

*Sulphur is not a hydrocarbon but it is included for practical purposes.

The field was practically fully developed by 1952, two years before the Leduc-Woodbend field. The D-3 Redwater wells were much more prolific producers than the D-2 wells of Leduc, and the oil companies postponed full development of the D-2 formation in the latter field and concentrated much of their drilling in Redwater, and in 1950 considerably more footage was drilled in Redwater than in the Leduc-Woodbend field (see fig. 24.) Drilling activity dropped sharply in Redwater during 1951 as the field became almost drilled out, and after 1952 drilling almost ceased. In the meantime, the Leduc footage reached its maximum in 1951 as the D-2 formation underwent rapid development. The number of wells capable of production in Redwater reached a peak of 926 in 1952; since then a few wells have been abandoned, leaving about 900 producers currently. Redwater is not a large gas-producing field because relatively little gas is produced with the oil. However, gas production became great enough to cause the Conservation Board concern over flared gas; it

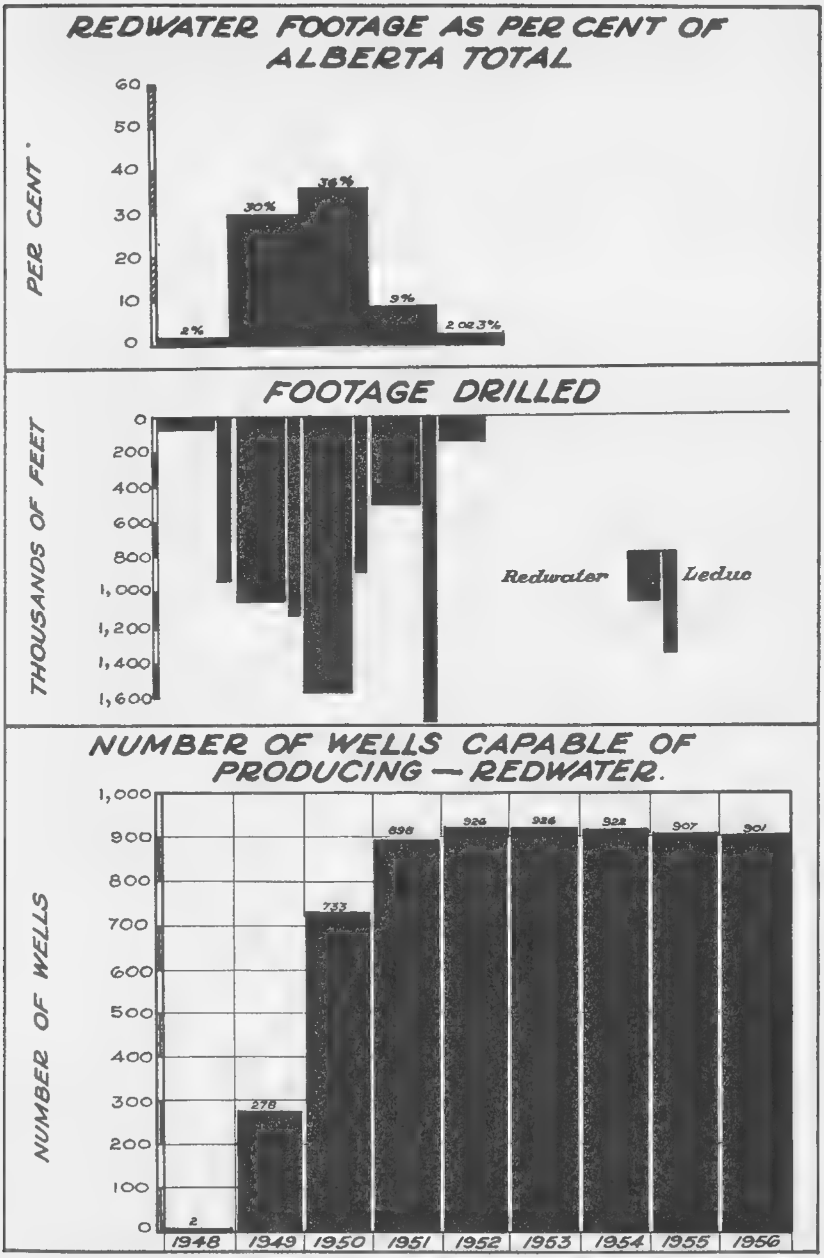


Fig. 24 Drilling activity in the Redwater Field, 1948-56
Source: PNGCB.

ordered the construction of a gas conservation plant. This was duly undertaken and completed by Imperial Oil in 1956 at a cost of three million dollars. The plant is not a profitable venture and its value has to be assessed in terms of conservation principles. Redwater led Alberta fields in crude oil production in 1950-55 inclusive, but had to yield the leadership to the Pembina field in 1956.

The Effects of Redwater

The discovery of Redwater intensified the search for oil in Alberta and Western Canada, and after 1948 a number of important oil fields were discovered in the Edmonton area as well as in other regions. The discovery of Redwater also made the extension of markets imperative. Refinery capacity in Alberta and Western Canada was increased accordingly. The industry, which had thought in terms of a pipe line to Regina from the Leduc field, began planning a line to transport crude to the head of the Great Lakes. With further discoveries in 1949-51, extension of the line to Sarnia was decided on. The petrochemical industry began to lay plans for locating in Edmonton as the development of the Leduc and Redwater fields made it evident that there were large assured supplies of oil and gas and as Edmonton became a refinery centre. This is anticipating our story. What is perhaps of the greatest significance is that Redwater clinched matters and put Alberta into the major league of oil-producing regions with original recoverable reserves exceeding one billion barrels. Furthermore, it was the field that indicated the magnitude of funds that the petroleum industry could provide the treasury of the Alberta government.

9

More Discoveries, 1949-1953

Leduc and Redwater were the two initial discoveries which brought the spotlight on Alberta. They were also major fields since each had reserves in excess of 100 million barrels. In 1955 it was estimated that Leduc might ultimately produce about 225 million barrels of crude oil, while Redwater might produce 720 million barrels. These figures are only indicative of the order of magnitude of the fields since reserve estimates are revised continuously in the light of changes in reservoir technology and oil demand. This observation applies to all reserve estimates. In all cases they are only approximate and derived from several unofficial sources since there are no official estimates for individual fields published by the Alberta Conservation Board or any other body.

After 1948 several substantial and many small fields were discovered in the Edmonton region. Ultimately, too, important discoveries were made in scattered locations throughout much of Alberta. Fig. 25 indicates the main oil fields discovered between 1947 and 1953. The reader is referred to fig. 13 in Chapter 5 for fields found before 1947.

The Joarcam Discovery

In January, 1949, four independents, General Petroleums, Superior Oils, Kroy Oils and Jupiter Oils, spudded in a well near Joseph Lake, 25 miles southeast of Edmonton, on a farmout from Imperial Oil. The Joseph Lake area was about 30 miles directly east of the Leduc discovery, and the four companies intended to drill to the Devonian limestone. In March, Superior Joseph Lake No. 1 struck Viking sandstone and drill stem tests indicated the presence of oil in a seven-foot pay zone between 3,263 and 3,270 feet. Drilling to the Devonian formation was done to 5,215 feet but no oil or gas was found. The well was then plugged back almost 2,000 feet to the Viking formation and

put on production with an initial flow of 500 barrels per day of sweet, amber-green 37° API gravity crude comparable to that of the Leduc field. By contrast, Redwater crude is "sour" since it contains considerable amounts of sulphur and chlorides.

The discovery team developed the field rapidly and it was almost drilled out by the end of 1951. With relatively shallow drilling, wells took only a few weeks to complete as in Redwater where the drilling depths and conditions were comparable. Many wells took only a week or two for the drilling process itself. The Leduc-Woodbend field with its deeper wells and harder formations beyond the Viking required much more time and heavier rigs than Redwater and Joseph Lake.

Spearheaded by Socony-Vacuum, a number of companies, Imperial, Anglo-Canadian, Home, Calgary and Edmonton, British American and many others, found in 1950 and 1951 that the field extended in a south-easterly direction through the Armena and Camrose districts. Today there are about 475 wells dotting pleasantly wooded farm country in a two-mile strip for more than 25 miles from Joseph Lake to the city of Camrose. It is now known as the Joarcam field, after the first syllables of the place names—Joseph Lake, Armena and Camrose. Notable features of the field are the high porosity and permeability and the thin pay zone and the fact that it was Canada's first Viking field to become a commercial producer of crude oil. In 1956 it ranked seventh among Alberta fields in production with an output of 4.5 million barrels and was eleventh in terms of estimated ultimate recoverable reserves which exceed 60 million barrels.

The Golden Spike Discovery

The outstanding find of 1949 was at Golden Spike, 15 miles southwest of Edmonton (see fig. 25). Here Imperial Oil found a D-3 pay zone which extended for 544 feet from 5,362 to 5,907 feet. It turned out to be a very rich pool with recoverable reserves in the neighbourhood of 125 million barrels, but it was also a problem child which challenged petroleum engineers. The porosity was variable, the solution gas very unpredictable in lifting the oil to the surface and it was small in areal extent. Only seven wells were drilled, one per 160 acres, covering an area of about 1,100 acres. In subsequent years, Imperial found a D-2 pool and Canadian Oil and associated companies discovered additional D-2 and D-3 pools. These pools had only average pay zones and together they added less than five million barrels of reserves to the field. In 1956 the field ranked eighth in production in Alberta.

The underground pressure in the main pool declined rapidly and by 1952 it looked as if recovery would be but a small fraction of the esti-

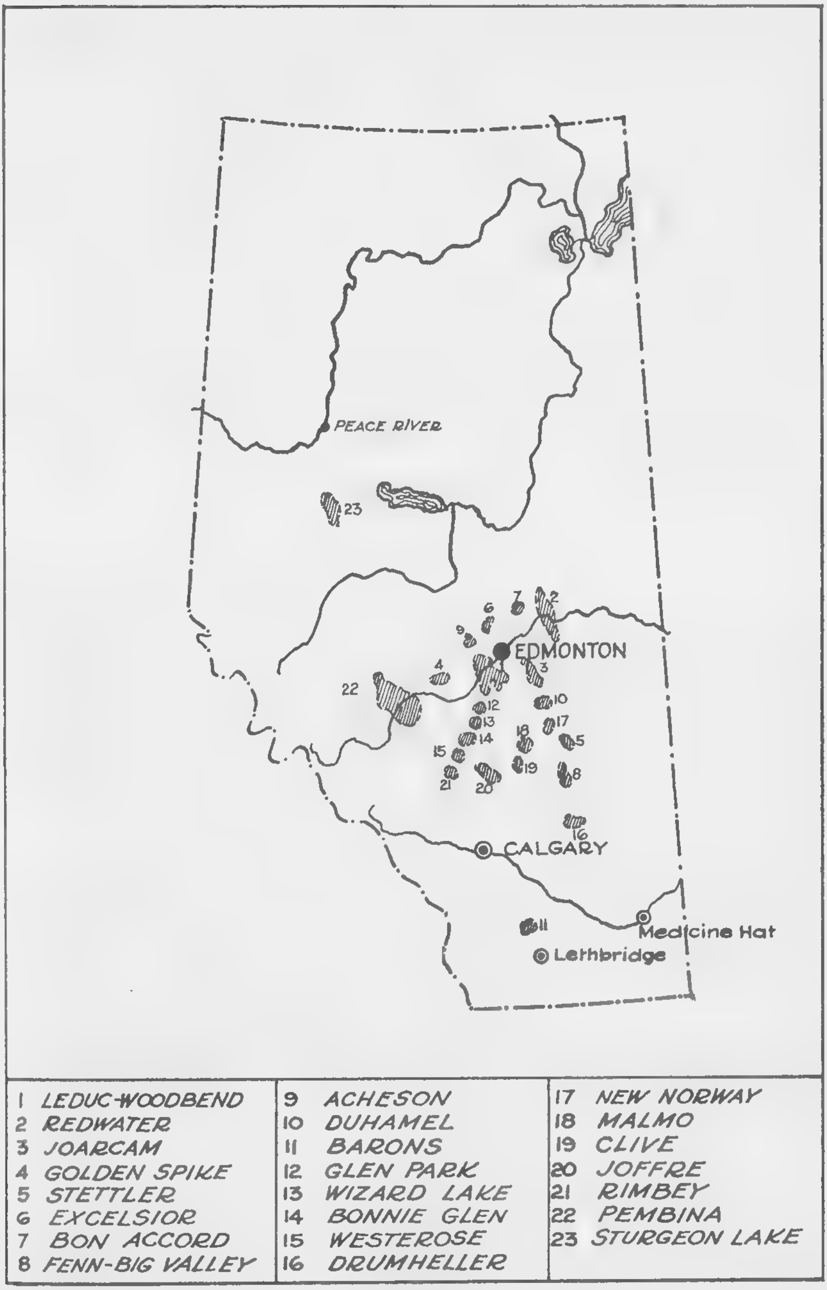


Fig. 25 Main oil fields discovered in Alberta, 1947-53

mated oil in place. Imperial Oil accordingly put its engineers to work to devise a suitable repressuring plant to increase ultimate recovery. In the spring of 1954 the Golden Spike pressure maintenance project was completed at a cost of $3.3 million. Additional wells were drilled to Viking, Lower Cretaceous and D-1 formations to provide gas for injection into the D-3 oil wells. Gas was also piped in from the nearby Devon gas conservation plant. The pressure maintenance plant is capable of injecting gas into the oil wells at the rate of 20 million cubic feet per day. The project may mean the ultimate recovery of 60 per cent of the oil in place instead of 20 or 25 per cent. Since the D-1 and Lower Cretaceous gas contains hydrogen sulphide, a hydrogen sulphide unit was also built to scrub the gas at a rate of up to five million cubic feet per day. When the field ceases to produce oil, there will be an estimated 150 billion cubic feet of natural gas available for withdrawal in the Golden Spike formation after the injected gas has done its work.

Other Discoveries in 1949

A new Devonian field was discovered near Stettler, about 100 miles southeast of Edmonton (see fig. 25.) The Canadian Gulf Company brought in the N. J. Ellis No. 4 in a D-2 zone in November, both at depths approximately those of the Leduc-Woodbend zones. The oil was of intermediate gravity, testing about 28° API. With reserves in the neighbourhood of 25 million barrels, the Stettler field ranked twelfth in output in Alberta in 1956 with a production of 2.1 million barrels from 107 wells.

Other Devonian fields were found by Imperial Oil at Excelsior, 15 miles northeast of Edmonton, and at Bon Accord, a few miles from the Excelsior find. The Excelsior field was a ranking producer in 1956 with an output of one million barrels. Small Lower Cretaceous discoveries were made at Whitemud, a few miles south of Edmonton, at Campbell, just north of Edmonton and at Stettler, but these have not become significant producers and each has reserves below one million barrels. Imperial also found the first indications of oil in the Peace River region at Normandville, more than 250 miles northwest of Edmonton.

Discoveries in 1950

The search for Devonian fields continued throughout 1950. The greatest discovery of the year was made at Big Valley, south of Stettler, by the Canadian Gulf Oil Company. Subsequent ex-

tensions indicated a field with more than 100 million barrels of recoverable reserves. Currently, the Fenn-Big Valley field has more than 300 producing wells and it ranked as Alberta's fifth producer in 1956 with an output of eight million barrels.

Another noteworthy Devonian discovery was made by Imperial and California Standard at Acheson, eight miles west of Edmonton. The reserves of the Acheson field have been estimated at about 75 million barrels. The field ranked tenth in production in Alberta in 1956 with an output of 2.6 million barrels. A small Devonian field with estimated reserves of less than five million barrels was found at Duhamel, 12 miles southwest of Camrose, by the Socony-Vacuum Exploration Company.

Several minor discoveries of fields with estimated reserves of one million barrels or less were made. They were mainly in Lower Cretaceous formations. At Barons, 20 miles north of Lethbridge, The Barons Oil Company found light gravity oil in Fish Scale sandstone of Upper Cretaceous age. Compared with 1947-49, the discoveries of 1950 were not outstanding, but they were more than sufficient to encourage exploratory drilling.

Discoveries in 1951

With the widening of the market for Alberta crude to the east and with the prospects of a Pacific coast market, exploration drilling rose markedly in 1951. More than one exploratory and two development wells were drilled per day, on the average. There were many discoveries, mostly of small fields with recoverable reserves from a few hundred thousand barrels to 10 million barrels.

The major find of the year was at Wizard Lake, about five miles south of the Leduc Woodbend field (see fig. 25). The discovery well was drilled by the Texaco Exploration and McColl-Frontenac team and was completed in the D-3 zone in May, 1951. The field, despite its small area of barely 2,000 acres, proved to be prolific. The pay zone, while still short of the record held by Golden Spike, averaged almost 350 feet in thickness. The gravity of the oil was about 38° API. Recoverable reserves have been estimated at 130 million barrels, making Wizard Lake a major field. It ranked sixth in production in Alberta in 1956 with an output of 4.8 million barrels. Its discovery stimulated drilling greatly in the territory south and southwest of the Leduc-Woodbend field.

The second largest discovery of the year was at Glen Park, just between the southwestern tip of the Leduc-Woodbend field and the Wizard Lake field, where a British American-Shell team brought in a well in September. Like the Wizard Lake discovery it had to be drilled to more than 6,000 feet to reach the D-3. The oil was light gravity, up to 44° API, the

pay zone exceeded 100 feet, but the area of the pool was only about 500 acres. The recoverable reserves have been estimated at 13 or 14 million barrels.

The other pools discovered during the year had recoverable reserves of five million barrels or less. The Naco and Dome Exploration companies joined forces to drill the discovery well in a D-2 zone at Drumheller which was completed in November. Socony-Vacuum discovered oil in the D-2 zone at Duhamel in August. There were some further discoveries in the Golden Spike area, in both D-2 and D-3 zones. A dual zone field with D-2 and D-3 producing zones was discovered at New Norway, about 50 miles southeast of Edmonton. Here Canadian Superior Oil of California brought in a D-2 producer in December. There were several minor discoveries throughout Alberta at Namao, Alliance, Armisie, Bashaw, Baxter Lake, Bonnyville, Cessford, Chamberlain, Peavey and Skaro.

Discoveries in 1952

Exploration drilling reached a peak in 1952 and 551 wells were drilled, about one third more than in 1951. There were great rewards for several companies for their efforts.

The Texaco-McColl-Frontenac team scored again in 1952 when it brought in the discovery well of the Bonnie Glen field, just south of the Wizard Lake field, in January. Here drilling to 6,382 feet was required before the D-3 zone was encountered. The next 400 feet was a tremendous gas cap containing both gas and naphtha with 60° API gravity. Below this was an oil pay zone of nearly 300 feet with 42° API gravity crude oil, making the total D-3 gas-oil pay zone almost 700 feet. The estimated recoverable reserves were almost 300 million barrels, making the field the third largest found in Alberta to date. In 1956 it was the fourth largest producer in the province with an output of 10.3 million barrels from the 149 wells. Remarkable features of the field are the thick pay zone, the light gravity oil, the relatively small area, the high output per well and the high recovery factor.

The discoveries of Glen Park, Wizard Lake and Bonnie Glen, stretch southwestward from the Leduc field like three pearls. They stimulated intensive drilling to the southward and the result was the discovery of a fourth D-3 field at Westerose, just south of the Bonnie Glen field. Here the C.P.R. Fiveland No. 4 was brought in as a D-3 producer in September, after drilling more than 7,000 feet. Westerose was the second largest discovery of 1952 with estimated reserves of about 50 million barrels. The field was unitized and in 1956, 19 wells, spaced 80 acres apart, produced 2.3 million barrels.

At Sturgeon Lake, about 200 miles northwest of Edmonton, the Amerada Company drilled to 8,700 feet and found high-gravity crude in a D-3 formation termed Woodbend Reef (see fig. 25). Estimated recoverable reserves in this remote field ran between 25 and 30 million barrels. A D-2 pool was found at West Drumheller with reserves exceeding 10 million barrels. Sun Oil, Scurry Exploration and associated companies brought in a three-zone field—Lower Cretaceous, D-2 and D-3—at Malmo, about 55 miles southeast of Edmonton; the combined reserves of the three pools were not quite 10 million barrels. A dual zone field (D-2 and D-3) was found at Clive, near Stettler. Other finds of some significance were made at Cessford, Legal, Acheson and Chauvin.

Exploration in 1953

Exploration drilling in Alberta declined in both 1953 and 1954 and so did development drilling. There were several reasons for this. One was the increasing attention given to exploration and development in Saskatchewan and Manitoba where oil companies were experiencing a fair amount of success. Another was that in contrast to Leduc, Redwater, Joarcam and Fenn-Big Valley fields, the major finds of 1951-52, Bonnie Glen, Wizard Lake and Westerose, required relatively little development drilling. The economic adjustment in Canada and the United States in 1954 restricted the flow of funds into the petroleum industry to some extent.

In 1953 the Amerada Corporation discovered a large D-3 reservoir at Sturgeon Lake South near its Sturgeon Lake find of the previous year. Drilling depths in this field went to almost 9,000 feet. The estimated reserves were nearly 150 million barrels, making it Alberta's fifth largest field. The two Sturgeon Lake discoveries were both in a remote area, far from railways, and in rough country. A pipe line was accordingly constructed to the Trans Mountain line, and by 1956 the Sturgeon fields became significant producers of oil. The development of the fields is not yet completed. Here, too, is another oil town, Valleyview, which has grown from a hamlet with only a few residents to an oil supply and service centre with a population of more than one thousand.

An important field discovered in 1953 was the Joffre, which extends eastward from the City of Red Deer along the Red Deer River. Here oil was found in Viking sandstone at a depth of about 5,000 feet, and the field ranks second after Joarcam as a Viking producer with estimated recoverable reserves of about 20 million barrels. Canadian Superior made the discovery in September, 1953, and the field is now almost completely developed.

In May, 1953, the Calmont Company discovered a 10-million-barrel field at Rimbey, about 20 miles south of Westerose, in a D-3 zone at a depth of 8,000 feet. Another D-3 field with reserves of nearly 10 million barrels was discovered at Erskine, east of Stettler, in June, by the team of Mitmore-Merland-Merrill oil companies. Smaller discoveries in the D-3 were made at St. Albert, near Edmonton, and at Fairydell, near Bon Accord. Still smaller discoveries were made at Acheson East, Battle, Ewing Lake, Gilby, Glen Park and Samson.

The story of exploration in Alberta during the six years 1947-53 was mainly one of Devonian discoveries which extended in a southeasterly direction from Sturgeon Lake through the Edmonton region down to Drumheller. No field found during the period rivalled the great Redwater in reserves and only one, the Bonnie Glen, was greater than Leduc. Of the 18 fields in Alberta which produced one million barrels or more, thirteen were Devonian and they were all discovered during 1947-53. Three of them were Lower Cretaceous (Joarcam, Joffre and Lloydminster) and one, the Turner Valley, was Mississippian. The eighteenth was the Pembina field which exceeded all the rest in production, reserves and areal extent. It was not only the greatest discovery of 1953 but also of the whole decade, and it is so important that it merits separate discussion.

10

Pembina

In June, 1953, the Socony-Seaboard team discovered oil in Cardium sandstone, an Upper Cretaceous formation, near Drayton Valley, some 85 miles west and south of Edmonton by road. It took a long time to evaluate this discovery; indeed, it was not until well into 1954 that it became clear that Alberta's largest oil field to date had been found, the Pembina, so named after the river flowing through it. Another great land rush was on and drilling activity was stepped up again. The Pembina gave indications of being a one-billion-barrel field and it covered a large area which required an intensive program of development drilling. Exploratory drilling was also stimulated, and its emphasis turned from trying to find Devonian limestone zones to attempting to discover oil-bearing Cardium sands of the Upper Cretaceous.

The Pembina River flows from the Rockies east and north to the Athabasca through foothills, muskeg, forest and some farm country. In the area surrounding Drayton Valley the Seaboard Oil Company and associates acquired reservations from the province. Much of the country was covered by muskeg and the Seaboard seismic crews which went to work on the reservation had to operate in the winter time if they were to move their equipment at all. Muskeg is soft, treacherous ground and in summer it can easily swallow up the trucks of a seismic crew.

The Socony-Vacuum Exploration Company obtained a farmout of almost 100,000 acres from Seaboard in early 1953. The farmout gave Socony a half interest in this acreage in return for the drilling of one well to the Devonian. Socony obtained the services of the Reading and Bates Drilling Company which spudded in a wildcat, Socony-Seaboard Pembina No. 1, on L.S.D. 4, Section 16, Township 48, Range 8, West of the Fifth Meridian, on February 24, 1953. It was a rank wildcat as can be seen by examining fig. 26. No successful oil wells had been drilled in the area.

The drillers reached Devonian green shale and stopped at 9,425 feet

on May 15. There were no showings of oil except in the Cardium sandstone layer from 5,310 feet to 5,365 feet and drill-stem tests revealed nothing spectacular. But since they indicated some oil, preparations were made to see if it would flow. The hole was plugged back about 4,000 feet to just below the Cardium zone. The casing in the pay zone was perforated and the well was swabbed after which a few gallons of 37° API oil were recovered. A well-completion contractor was then called in, but his service rig did not arrive until early June. The well was treated and swabbed and was finally completed on July 1, 1953, with an initial potential of six barrels of oil per hour.

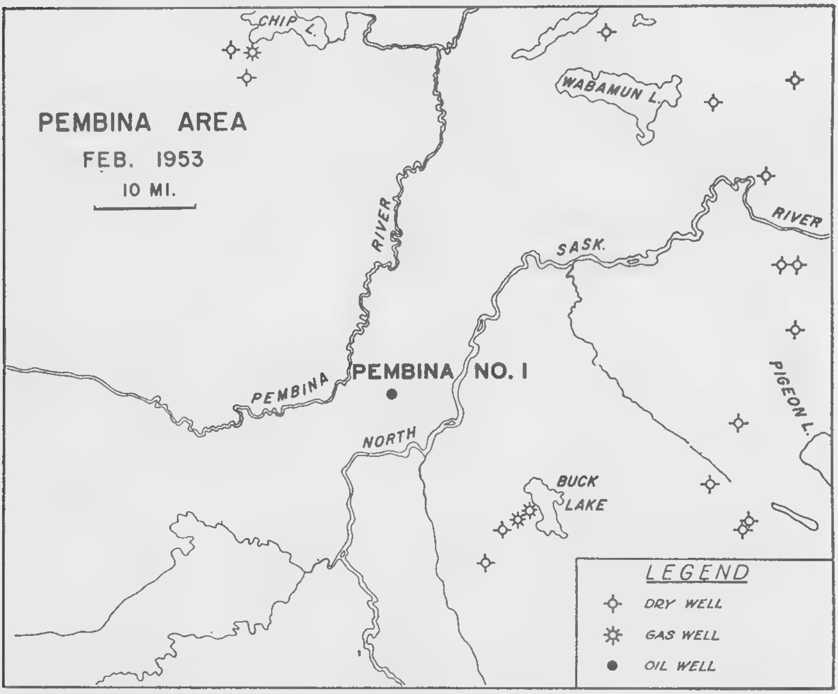


Fig. 26 The Pembina area, February, 1953
Courtesy of Mobil Oil of Canada

It was then decided to put the well through a 30-day production test, but heavy rains made whatever roads there were in the area impassable and oil could not be transported to the provincial highway and the railroad, about 30 miles to the north. The provincial government imposed a ban on the use of roads by trucks in the area for two months and the production test was delayed until September. The well flowed at 200 barrels per day, making it a find that was certainly not to be ignored.

Two more wildcats, one about 12 miles and another six miles northeast of the discovery well, were drilled in 1953. The more remote one yielded no oil, and was abandoned. The other came in as a producer in late 1953 and flowed at the rate of 20 barrels per hour without treatment.

By this time, other companies began to realize that there was something significant going on in the Pembina area, even though the reports on the discovery wells were not inspiring. On January 26, 1954, the provincial government, which owned nearly all the mineral rights in the area, held its first Pembina auction sale. The bids were high, with half a million dollars plus royalties on production being paid for each of a number of quarter sections. Imperial Oil and The Texaco Exploration Company paid $11 million and $13 million respectively for reservations west of the proved area. Both reservations were in remote muskeg country, the drilling difficulties were formidable, and little oil was found.

All the companies had difficulties in organizing their drilling programs. The rainy summer of 1954 made the muskeg almost impassable. The only way to get the crude oil out was by truck to Edmonton or to the Trans-Mountain Pipe Line; this was not easy because there were no all-weather roads to the field. The Pembina Pipe Line Company was granted a franchise to construct a pipe line to Edmonton in 1954, and construction of it was completed by the end of the year. Field gathering lines have been laid yearly by the company with the expansion of the developed area of the field.

The average drilling depth in Pembina is about 5,300 feet, about the same as in the D-3 pool of the Leduc-Woodbend field; the productive formation is Upper Cretaceous Cardium sandstone with an average pay zone between 15 and 20 feet. The gravity of the oil varies from 37° to 39° API; the crude is greenish-brown in color, with a paraffin base, and it is practically free of sulphur. The total area of the pool is estimated at about 460,000 acres or approximately 720 square miles, roughly 18 times the size of the Leduc-Woodbend field. By the end of 1956 about two thirds of this area had been developed, and intensive development drilling is still going on. The porosity is relatively high but the permeability is erratic and often lacking and the solution-gas pressure has declined rapidly. The unsatisfactory permeability and the fall in reservoir pressures create a low recovery factor of not much more than one fifth of the estimated five billion barrels in place. Notwithstanding, Pembina still is a field with more than one billion barrels of recoverable reserves.

At the end of 1953 Pembina had four producing wells. The rainy summer of 1954 and the lack of storage and transportation hampered development greatly. By the end of that year, 140 wells were producing and oil was flowing through the pipe line to Edmonton. Total production for 1954 was 842,000 barrels as against 39,000 barrels in 1953.

The provincial government took a hand by building a gravelled road to Drayton Valley and to Violet Grove and Lodgepole which were little post office centres before the oil discovery. From there the road went northward through the Cynthia area to the Edmonton-Jasper highway. Another road was built eastward from Drayton Valley to a ferry on the North Saskatchewan River. In addition, the oil companies have constructed about 300 miles of operational and drill site roads throughout the bleak, often burned-out, muskeg country.

With the provision of roads, development drilling proceeded very rapidly, and throughout 1955 and 1956 more than 1,500 development wells were drilled with hardly a dry hole, a remarkable record. Production rose so rapidly that by August, 1956, the field became Canada's leading producer with an output of over 100,000 barrels per day. The following table indicates the progress since the field was discovered:

	Number of Producing Wells	Production of Crude Oil thousands of barrels
Year 1953	4	39
1954	140	842
1955	808	14,850
1956	1,680	33,701

Medium-sized rigs are generally used in the field, equipped with blowout prevention equipment because of high initial pressures in many wells. Directional drilling contractors came in during the early stages to do directional drilling which is often necessary in the muskeg and because of the streams of the area. The limits of the field have not yet been definitely established, and many outpost and wildcat wells have been drilled west and south of the field during the last two years. In accordance with regulations laid down by the Conservation Board, well-spacing is one well per 80 acres and in some cases 160 acres. It is expected that the development of the field will continue into the early 1960's with from 500 to 1,000 well-completions in each year. Ultimately the field may have as many as 6,000 wells. Fig. 27 shows the extent of the field in early 1957.

The Pembina field has posed some producing problems which normally occur only years after a field has been in operation. The sandstone usually needs shooting treatment to fracture it and increase permeability. Solution-gas pressures have gone down greatly and many pumps have had to be installed. Since the oil is high in paraffin content, waxing is a problem, and in winter the crude has to be heated for ease of transmission through pipe lines. The poor permeability of the field has led operators to con-

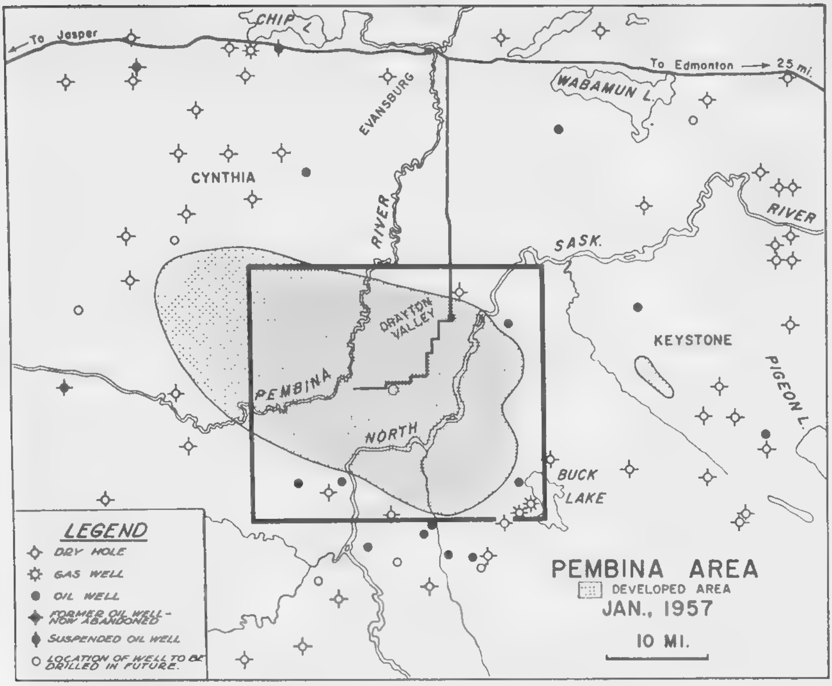


Fig. 27 The Pembina area, January 1957
Courtesy of Mobil Oil of Canada

sider secondary recovery methods. A proposed remedy is hot-water injection, and in 1956 James A. Lewis Engineering, a petroleum reservoir consulting firm from Dallas, Texas, completed a report on the use of secondary recovery methods for the Canadian Seaboard Oil Company. The Lewis Report recommended the construction of hot-water injection plants and that hot water be injected into every second well at the rate of one barrel for each barrel of crude produced from the other wells. The water could be heated by gas produced in the field. Petroleum engineers are also considering the injection of gas, propane and carbon dioxide when these became available in sufficient quantities. Currently, an $18-million gas conservation plant is being planned.

The little hamlet of Drayton Valley mushroomed, like Redwater did, into a town with 2,000-3,000 people within two years of the discovery date. No operator in the field was dominant in it to the extent that Imperial Oil was in the Leduc-Woodbend field. Hence no one undertook the construction of a "model town" such as Devon, and the provincial government and the school division in the area struggled with the problems of providing school and health services.

Living conditions in the Pembina area were uncomfortable and harsh until the provincial government laid out Drayton Valley. There were few permanent houses at first and most people lived in trailers. There were no water-and-sewage and no electric-power systems. During the exceptionally rainy summers of 1953 and 1954 it was often impossible to get to the railway or highway, 30 miles distant, unless one walked or used horses. In winter, the road to the north often drifted in. Until the province engaged the services of the Royal Canadian Mounted Police in 1955, Drayton Valley was almost reminiscent of a wildwest town of the nineteenth century. A large hotel was completed in late 1954 which helped to alleviate the housing problem of the traveller.

Drayton Valley became what is termed a "new town" in special Alberta government municipal legislation in 1956. Previously it had been administered by the provincial government under a statute pertaining to sparsely settled rural areas called "improvement districts". Under the "new town" statute it continued to be administered by the provincial government, but under a set of legislative rules applicable to new growing urban centres. A number of permanent residences have been built to accommodate oil personnel. The town serves as a supply and service centre and many oil industry contractors and supply houses have branch offices and depots in it. Electric power and a water and sewer system have been provided. The school facilities have been expanded greatly, and a hospital is being constructed. There is a general air of prosperity about the town despite the hundreds of automobile trailers which occupy blocks of it. There has been a great influx of workers. Very few farmers owned the mineral rights but they obtain surface right payments.

Southwest from Drayton Valley are two smaller supply and service centres, Violet Grove and Lodgepole. Some 25 miles west of Drayton Valley and north of Lodgepole, a new town called Cynthia is being developed. The provincial town planners are making careful studies of the future potential of these towns in order to advise on such matters as the installation of municipal utilities, the construction of schools and the provision of "civilizing" services.

The development of Pembina will take several more years for drilling alone. The intensive use of secondary recovery methods will generate a continuing need for personnel. Well-servicing and transportation will occupy many more people as additional wells are completed. If the recovery factor could be raised from its present low level by secondary methods to something like 50 per cent, Pembina would become at least a 2½-billion-barrel field. But to achieve such a level of cumulative production, the engineering techniques must be effective and not too costly in relation to the price of crude oil. Increases in the price of crude would give inducements to use secondary recovery methods intensively.

Discoveries in 1954-56

There were no major discoveries during 1954-56. The greatest additions to original recoverable reserves were those of Pembina as development proceeded. Pembina led to a search for Cardium sandstone fields and in 1954 two were discovered at Alhambra and Rocky Mountain House, more than 40 miles west of Red Deer and about 50 miles south of Pembina. Other 1954 discoveries were D-3 pools at Little Smoky in the Grande Prairie country and at West Drumheller, a D-2 pool at Fairydell, two Viking pools at Battle, about 50 miles southeast of Edmonton, and Lower Cretaceous pools at Acheson and Wayne. None of these fields appears to have reserves in excess of five million barrels. This was quite a letdown, for in every year beginning with 1947 a field of more than 100 million barrels had been discovered: Leduc in 1947, Redwater in 1948, Golden Spike in 1949, Fenn-Big Valley in 1950, Wizard Lake in 1951, Bonnie Glen in 1952, Pembina and Sturgeon Lake South in 1953.

In 1955 sizeable discoveries were made in the Calgary area in Mississippian Rundle limestone formations at depths of about 9,000 feet. The most important was the Harmattan-Elkton field, about 45 miles northwest of Calgary. The recoverable reserves of this field are estimated to be in excess of 50 million barrels, making it the greatest discovery since Pembina and Sturgeon Lake South. The oil has a gravity of 36° API and it is now piped to the Calgary refineries, which for several years had depended largely on crude from Central Alberta fields because of Turner Valley's dwindling output. A few miles northwest of Harmattan-Elkton, a smaller field with reserves of less than 10 million barrels, Westward Ho, was found in the Mississippian. Fifteen miles north of Westward Ho, the Sundre field was discovered, also in the Mississippian, and its reserves are estimated at 30-40 million barrels. These discoveries revived interest in drilling in the Calgary area and with the construction of a pipe line have also led to expansion of refinery capacity in Calgary.

Relatively small discoveries were made in 1955 at Bellshill Lake, about 100 miles southeast of Edmonton, in the Lower Cretaceous, at Hespero in the Alhambra area and at Sturgeon Lake South where some oil was found in a Triassic formation. There were also a number of the usual finds of very small pools. Some of these have not been fully assessed yet.

The potentials of discoveries in 1956 are not yet known. A Viking field with a probable reserve of two or three million barrels was found and developed during the year at Bentley, some ten miles south of Rimbey. The Texaco Exploration Company found the first commercial D-1 (Wabamun) producer near High River, about 30 miles south of Calgary, east

FIG. 28

MAIN OIL FIELDS DISCOVERED IN ALBERTA, 1954-56

1 PEMBINA (For reference)
2 ROCKY MOUNTAIN HOUSE
3 ALHAMBRA
4 KEYSTONE
5 LITTLE SMOKY
6 STURGEON LAKE SOUTH
7 BELLSHILL LAKE
8 CUTBANK EAST
9 RED EARTH CREEK
10 SUNDRE
11 WESTWARD HO
12 ELKTON-HARMATTAN.

of Turner Valley. The Devonian was reached at 9,600 feet and an oil pay zone at 9,622 feet. A production test resulted in a flow of more than 300 barrels per day of 39° API crude. The area is now undergoing development.

Two other discoveries, both in the northern part of the province, caused some excitement. One was made by Baysel Company and associates at Cutbank East, about 40 miles south of Grande Prairie. It was in Cardium sandstone at nearly 5,300 feet. Considerable drilling is being done to test the area by several companies. The other was the Red Earth discovery of the Union Oil Company, east of the town of Peace River, in very inaccessible country. A well completed in March, 1954, the Great Plains-Triad-Muskeg-Gilwood 1-9, had indicated the presence of oil. The notable feature of the discovery is that oil was found in a formation new to Alberta, the Granite Wash, near the Pre-Cambrian. Greenish-brown sweet crude with a gravity of 38° API was found at about 4,750 feet. Development is discouraged by the remoteness of the area and the difficulties of working in the muskeg in the summer. It is doubtful that it would pay to develop the field intensively at this time. It remains a potential reserve, although no one can say how great it may be as yet.

The northern part of the province appears to have great potential. Exploration and drilling in this vast uninhabited region may result in the discovery of fields comparable to the largest yet found in Alberta. However, there still remains a great amount of exploratory work to be done in the southern part of the province.

11

Ten Years of Achievement

The petroleum industry has come a long way since the first commercial oil well was completed in 1914. During the initial decade of 1914-24 the number of producing wells could be counted on the fingers of one hand; during the 1925-36 period which followed the Royalite discovery, producing wells came to be counted by the dozen; the third plateau was reached in 1937-46 when hundreds of wells came in. But it was the fourth decade of 1947-56 which brought about profound and far-reaching developments as the number of wells completed amounted to thousands. The following table on crude oil production in Alberta provides a quick perspective of the change since 1926:

	Number of Wells Producing Oil	Production of Oil Millions of barrels	Value of Oil Produced Millions of dollars
Year 1926	10	0.2	0.9
1936	129	1.3	2.9
1946	418	6.7	12.7
1956	7,390	143.9	355.2

This appears to be a convenient point at which to summarize the growth of the production activities of the petroleum industry in Alberta.

Land Acquisition

The total acreage under lease and reservation in Alberta rose from an estimated 15 million acres in 1946 to 100 million

acres at the end of 1956. Complete data for the whole period are not available, except for provincial government lands. Fig. 29 sets out the changes in such lands leased and reserved by oil and gas firms in 1946-56. The downturn of 1951-53 was attributable mainly to the decline in exploratory activity which was mentioned in a previous chapter. During the 1950's there was a tendency for companies to become increasingly

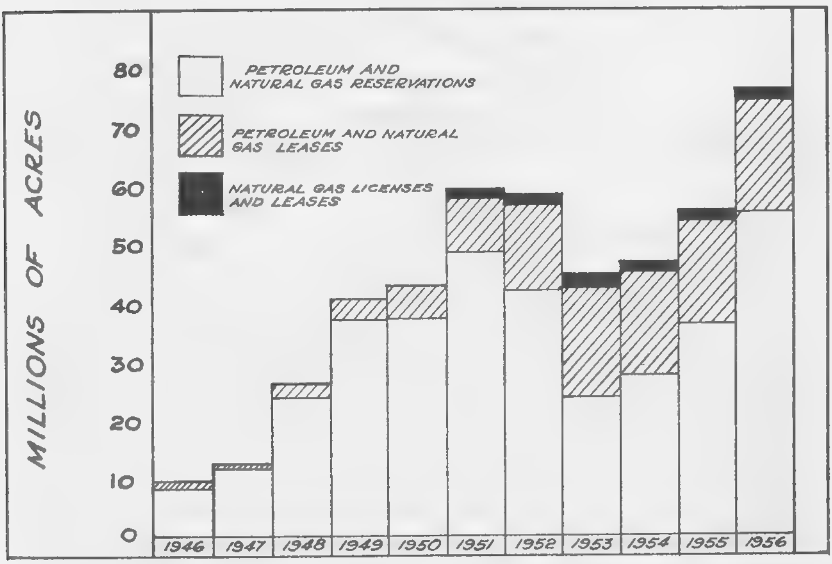


Fig. 29 Petroleum and natural gas leases and reservations of the Government of Alberta, 1946-56 (millions of acres)
Source: Government of Alberta, Dept. of Mines and Minerals

selective in taking out reservations and leases in the southern part of the province as exploration and drilling provided knowledge about various areas of it. On the other hand, there was a marked increase after 1954 in the acreage reserved and leased in the northern part of the province, most of which is still largely unexplored and untouched by the driller.

The provincial government was by far the largest holder of mineral rights and the table on p. 112 shows the situation at the end of 1956.

We shall have occasion to examine the provincial government's land regulations in detail in a subsequent chapter. The total acreage under lease and reservation at the end of 1956 represented about three fifths of the whole area of the province; this gives an indication of the widespread land play and exploration program going on.

Estimated Petroleum and Natural Gas Holdings Leased and Reserved to Oil and Gas Companies, in Alberta, December, 1956.

In millions of acres

Provincial Government	84.9
Canadian Pacific Railway	7.9
Freehold	4.1
Hudson's Bay Company	1.6
Indian Lands	0.9
Other	0.8
Total	100.2

Source: Canadian Petroleum Association.

Geological and Geophysical Surveying

Geological parties and geophysical crews spread out from the Edmonton area during the first few years after 1947. Exploration gradually came to be undertaken in the more inaccessible areas in the northern part of the province and much of this area still remains to be explored for the first time. Considerable territory surveyed in previous years has been worked over again; seismic crews still do some work in the Edmonton area. Once, or even twice over, is seldom enough to establish reasonably definite conclusions unless the operations are very thorough in their coverage.

In 1946 there were barely a dozen geophysical crews in the field in Alberta. Their number rose from 15 at the end of that year to a peak of 142 at the end of 1952. Since then the number has fallen, and at the end of 1956 only 92 crews were active in Alberta. Much of the decline is attributable to the shift of interest in exploration to areas in the other western provinces.

Geophysical methods were of the greatest significance in discovering most of the oil fields surrounding Edmonton. Geophysical parties are sent out into areas indicated as prospective by geological surveys to prepare subsurface contour maps of geological structures. These maps are then studied to try to deduce the presence or absence of favourable zones.

Several instruments and methods are in use. One instrument is the magnetometer which is an adaptation of the miner's dip needle; it measures the magnetic attraction exerted by underground rock formations. Another is the gravitymeter which is a very sensitive spring balance,

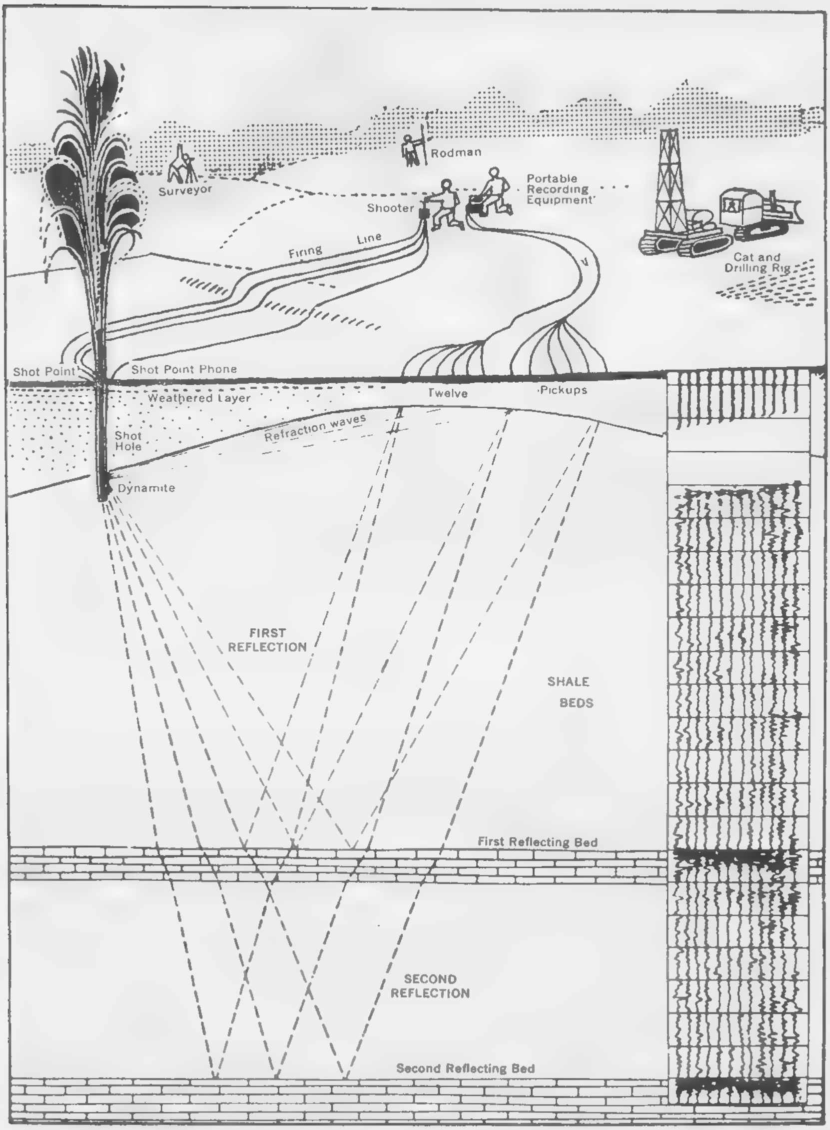


Fig. 30 A seismic crew at work *Courtesy of Royalite Oil Co. Ltd.*

equipped with mirrors and a telescope, enclosed in an insulated case. It measures the gravitational attraction of different rocks; these rocks have varying specific gravities and hence affect the gravitational pull of the earth. But the most commonly used geophysical instrument is the reflection seismograph. In Alberta it is used almost to the exclusion of the other

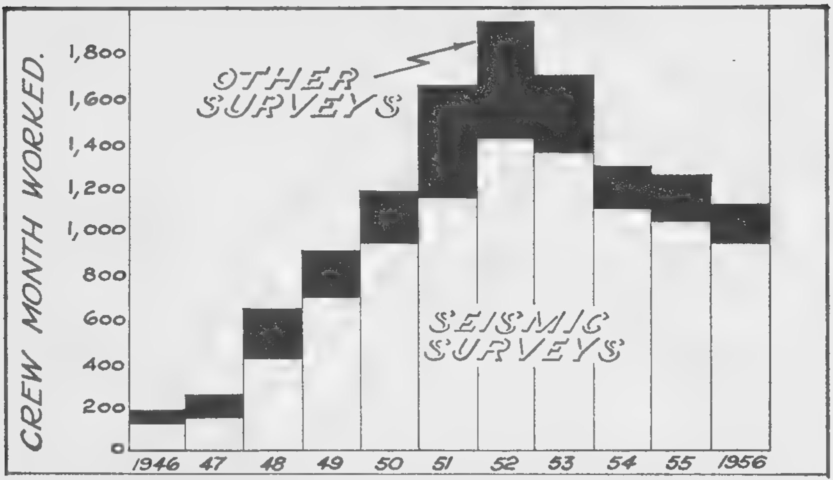


Fig. 31 Survey activity in Alberta 1946-56, in crew-months worked
Other surveys include gravitymeter, magnetometer, core drilling and surface party activities   Source: Imperial Oil

two. It measures the speed at which sound travels through the earth; this rate is low in soft sedimentary formations and high in hard rocks. Fig. 30 shows a diagram of a seismic crew in operation and provides a brief explanation of their operations.

The seismograph does not point infallibly to oil and gas pools; it does help to locate structural unconformities and faults in geological formations which are often associated with oil and gas. When it was introduced to Alberta, however, it was not long in producing results.

The bulk of survey work in Alberta since 1946 was seismic. In recent years it accounted for four fifths of the number of crew-months worked. Gravitymeter surveying was fairly important relatively until 1948 but magnetometer crews have been used little. Considerable core drilling was done in 1949-53, but it has been negligible in recent years. Core drilling, incidentally, consists of drilling to depths of several hundred feet by the use of light drilling rigs to obtain samples of rock formations. The geological surveys undertaken by surface parties have increased steadily throughout the period, but accounted for only one tenth of total crew-months worked in 1956. Fig. 31 illustrates the dominance of seismic surveys, the rise in survey activity in 1946-52 and the decline of 1953-56.

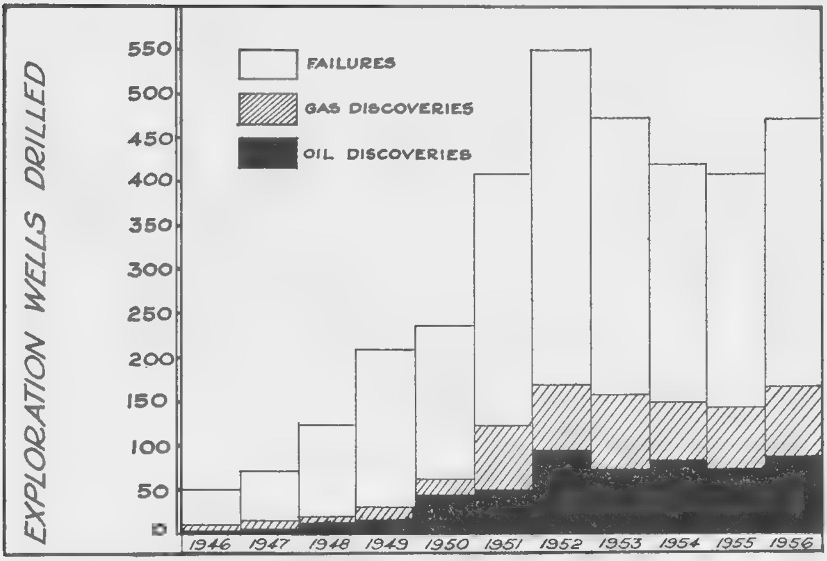


Fig. 32 Exploration wells drilled in Alberta, 1946-56
Source: Floyd K. Beach

Drilling

The number of drilling rigs in operation in Alberta increased from 20 at the end of 1946 to a peak of 183 at the end of 1951. There was a decline to 144 rigs at the end of 1953, followed by a rise as development of the Pembina field proceeded, and at the end of 1956 there were 167 rigs active in the province. This was about three fifths of the rigs active in Western Canada.

There are two categories of drilling; both involve the use of much the same techniques and equipment. One is exploration drilling and the other development drilling. Exploration drilling essentially involves the drilling of "wildcat" wells in areas where oil has not yet been found while development drilling consists of bringing proven and semiproven acreage into production. The definition of a "wildcat" well is a matter for the experts and a full explanation of the term cannot be given here. According to the journal *Canadian Oil and Gas Industries*, which publishes an annual "box score" of wells drilled in Canada, a "new-field wildcat" is a well drilled "far from producing pools and on a structure which has not produced before". A "new-pool wildcat" is a hole which is "located to explore for new pools on a structure already producing, but off to one side

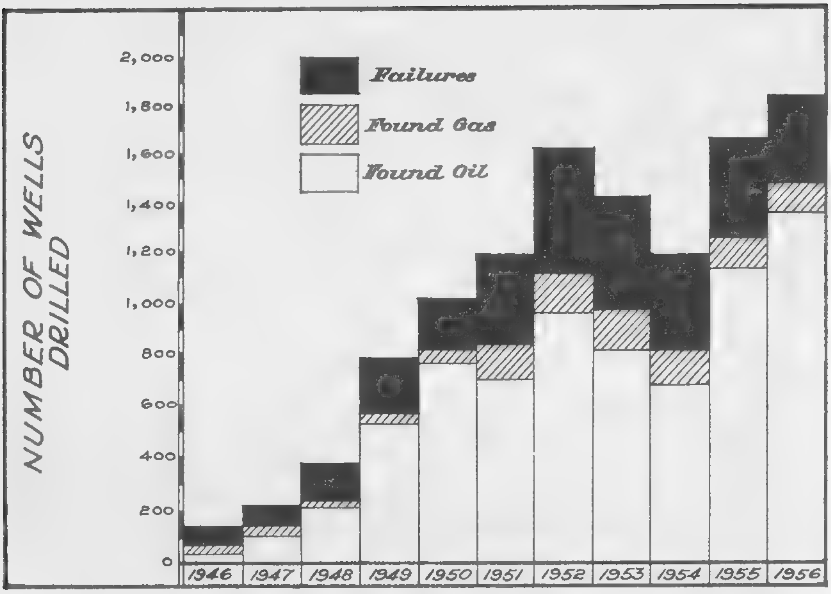


Fig. 33 Total wells drilled in Alberta, 1946-56
Source: Floyd K. Beach

of the presently producing area". Reference is also made to "shallower-pool tests" and "deeper-pool tests"; they are classified as exploratory under certain conditions. They are mentioned here since we shall resort to the data of Mr. Floyd Beach, Western editor of the journal and a veteran of many years in the petroleum industry. His records go back to the beginning of drilling for oil in Alberta and they provide a uniformity which no other series can provide.

The number of exploratory wells drilled in Alberta rose from 54 in 1946 to a peak of 551 in 1952, a tenfold increase. The number fell after that to 412 in 1955 and then rose again to 478 in 1956. Fig. 32 shows the changes in the number of exploratory wells and the success achieved throughout the decade. Exploratory drilling is a risky venture and the odds against the drillers are long as should be evident from an examination of the diagram.

Development drilling is done in an area where many characteristics of a pool or field are known. Consequently, the ratio of successes is high. The number of development wells drilled rose from 76 in 1946 to a peak of 1,063 in 1952 and fell to 765 in 1954. With the great activity in the Pembina field the number reached 1,378 in 1956. The ratio of success to the total number of wells drilled has exceeded nine tenths in almost

every year since 1946 and reached a high of 95 per cent in 1956, largely because of the great degree of success in the Pembina field.

Fig. 33 indicates the changes in the total number of wells drilled, both exploration and development. The ratio of dry holes or failures drilled declined from about one half in 1946 when exploration drilling was dominant to less than one quarter in 1950 when development drilling prevailed. The ratio rose again as exploration drilling became more important after 1951 and fell again after Pembina brought a sharp rise in development drilling. The dry-hole ratio of one fifth in 1956 is somewhat lower than the western Canadian ratio and considerably less than the one third which prevailed in the United States.

	Total Footage Drilled Millions of feet	Average Well Depth feet
Year 1946	0.4	3,090
1947	0.9	3,975
1948	1.7	4,450
1949	3.2	4,040
1950	4.3	4,280
1951	5.6	4,490
1952	6.6	4,070
1953	6.4	4,100
1954	5.7	4,825
1955	8.4	5,190
1956	10.1	5,320

Source: PNGCB.

More than ordinary depths have to be reached in Alberta to discover oil. The average depth of wells drilled in the world in 1955 was about 4,100 feet and about 4,090 feet in the United States. Saskatchewan wells averaged about 3,400 feet and Manitoba wells less than 2,000 feet. In Alberta, whose average altitude is considerably higher than that of its neighbours to the east, the average well depth was nearly 5,200 feet. As a result, the footage drilled in Alberta in 1955 was two thirds of the western Canadian total while the number of wells completed was only 56 per cent. There have been yearly variations in well depths because of the different kinds of fields being developed. The table above illustrates the differences during 1946-56 in Alberta.

A remarkable development in drilling is the achievement of greatly increased efficiency during the decade. In the United States the average

drilling time in days, including the dismantling and moving of rigs, decreased by more than one third in 1947-56 and the rate of penetration rose by almost one half. Comparable reductions in time were achieved in Alberta, and in many cases involving equivalent depths and geological formations, the drilling time has been cut more than one half since the Leduc discovery. In 1956 about 6,000 feet per rig-month were drilled in Alberta as against approximately 3,000 feet in 1947.

The reasons for the increased efficiency are found in drilling bits and equipment, in the use of more powerful motors, and probably also in the experience gained by the labour force in the contract drilling industry. This industry is highly competitive and contractors have had to try their utmost to effect improvements in techniques.

Reserves and Production

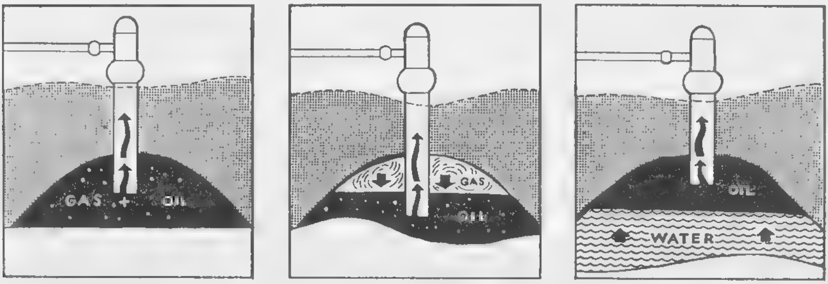
To make estimates of the recoverable reserves of a field always involves taking many factors into account. The process of arriving at answers is full of uncertainties which do not, however, detract from its peculiar fascination for petroleum engineers, geologists and oil evaluators. If we take the engineering estimates as given, various methods present themselves of doing the arithmetic and we shall work through one of the most common ways of calculating reserves.

The first point is that not all the oil in a pool can be withdrawn from the ground. Thus estimates of the recoverable percentage must be made, given existing production methods and costs of applying them. If someone devises improved production methods and field practices, the percentage recovered may be increased; if the price of crude oil rises it may pay to apply existing methods more intensively than before or to apply new methods to increase recovery. Any estimate made, then, is relative to wants and knowledge, to the demand for oil and the techniques by which it can be withdrawn, to the price of oil and the cost of getting it out of the ground.

Secondly, reserve estimates will change as a field undergoes development. As additional wells are drilled, the limits of the field gradually become known; the output of each producing well assists in making increasingly reliable estimates; data from the cores brought up provide useful information.

To illustrate the making of volumetric estimates of reserves, assume that the productive area of a pool is thought to be 1,000 acres. The productive thickness (oil pay zone) is 10 feet. Then the volume of productive reservoir is 10,000 acre-feet, where an acre-foot is one acre one foot thick.

Only a fraction of this volume consists of oil, gas and water and the fraction depends on the porosity, the capacity of the rock to contain fluid. Suppose the porosity of our pool is 10 per cent as determined by laboratory tests of rock samples. That is, 90 per cent of the volume of the rock is sheer rock and 10 per cent is oil, gas and water. Then the volume of the pores in the productive formation is only 1,000 acre-feet, one tenth of the 10,000 acre-feet of productive reservoir.



Dissolved gas drive. Expanding gas moves the oil

Gas-cap drive. A layer of gas pushes down on the oil

Water drive. Water below the oil forces it upward

Fig. 34 Types of drive that push oil

Courtesy of Harper & Brothers and reproduced from Oil for the World *by S. Schackne and N. D. Drake, revised edition 1955*

The next step is to estimate the volume of hydrocarbons in the pores that contain water; this is called "connate" or interstitial water. We shall assume that the connate water factor is 20 per cent. Then the hydrocarbon (gas and oil) content is 80 per cent of 1,000 acre-feet or 800 acre-feet.

We are still not finished for we wish to know the estimated "stock tank oil originally in place" (STOOIP) in the pool. To do this a shrinkage factor is calculated to allow for the separation of gas from the oil as production takes place. A barrel of hydrocarbons in the reservoir is reduced to less than a barrel of crude in the stock tank because of the gas taken out in the separator. Assume that the shrinkage is 20 per cent, leaving 80 per cent of 800 acre-feet, or 640 acre-feet, as stock tank oil. The volume of gas produced with crude oil is called the gas-oil ratio and is usually expressed as the number of cubic feet of gas produced with each barrel of gas.

One acre-foot equals 43,560 cubic feet and one barrel occupies 5.615 cubic feet; hence there are 7,758 barrels in an acre-foot. In our example there are 640 acre-feet of oil. Then the STOOIP is 4,965,120 barrels.

Not all of this oil can be recovered. Much depends on the permeability of the formation, the gravity of the oil, the equipment used, and above all, on the natural and artificial drives that may be employed. Shooting or acidizing can increase the permeability. Nothing much can be done about the gravity of the oil; the lower the API rating, the more sluggish it is and vice versa. If too much gas is permitted to be released with the oil, it may remove some vapours of light hydrocarbons that would normally remain with the crude oil in the pool. The crude oil gravity is lowered as a result, although the vapours in the gas may be recovered as natural gasoline.

The most important elements affecting recovery are the reservoir drives. The oil in the pores may flow up the well freely because of reservoir pressures or, as a last resort, it may have to be pumped up. There are three basic mechanisms whereby oil may be brought to the surface without pumping. One is called dissolved gas drive, whereby the gas dissolved in the oil is released from solution in the oil by the release of pressure when the hole drilled reaches the reservoir. The gas rises to the surface, bringing oil with it. This type of pressure or drive occurs when there is no free gas cap or free water layer in the producing zone. A second is called gas cap drive whereby the oil is forced upward by the downward expansion of a free gas cap. The third is termed water drive whereby the oil is pushed upward by the hydrostatic pressure of water below the oil sand or rock. Usually two or even all three of these drives are present in reservoirs in varying degrees; it is not often that one drive alone is present in a reservoir.

Controlling the flows induced by these drives so as to secure the most efficient production conditions and maximum ultimate recovery is a highly technical matter which demands the continuous attention of petroleum engineers. Economic and legal factors also bear upon the rate of production and the time of ultimate recovery of oil and gas. There are many examples in the history of the industry in the United States of too rapid production and quick depletion of fields with a resultant waste of energy and a low percentage of recovery of the oil in place. Turner Valley is an example of an Alberta field in which too much flush production was permitted, and it has been estimated that not more than 15 per cent of the estimated STOOIP of 750 million to 1,000 million barrels in the field will be recovered under existing conditions.

It has been realized gradually that there are optimum rates of withdrawal technically; these rates are in turn modified by price and cost considerations and by governmental regulations designed to maximize

Fig. 35. Core of Formation containing Oil

Reservoir Factors		**Composition of Rock**	
Porosity	.10	Rock	90.0%
Connate Water	.20	Connate Water	2.0
Shrinkage Factor	.20	Gas	1.6
Recovery Factor	.30	Oil which is not recoverable	4.5
		Recoverable Oil	1.9
		Total	100.0%

the percentage of oil or gas in place brought to the surface and to provide orderly marketing where there are many producers competing with each other in the sale of crude oil or gas. Even with the greatest attention paid to production techniques, some oil inevitably remains in a reservoir bed. Pumping and secondary recovery operations increase the percentage but these may be too costly in relation to the revenue currently obtainable from oil brought to the surface.

To get back to our arithmetic example, suppose that the reservoir engineers have studied the factors mentioned above and estimate the

primary recovery factor at 30 per cent. Then the estimated ultimate recoverable oil is 30 per cent of the 4,965,120 barrels originally in place, or 1,489,536 barrels. This is equivalent to 192 acre-feet, or not quite two per cent of the total 10,000 acre-feet in the productive formation, a mere drop of oil per cubic inch or rock. The estimated recovery factor may increase as more knowledge about a field becomes available and as recovery methods are improved.

The following summarizes the procedure and fig. 35 sets it out pictorially:

(a) There are 10,000 acre-feet of productive formation with the dimensions 1,000 acres in area and 10 feet thick.
(b) Since the porosity is .10, the volume of the oil, gas and water is only 1,000 acre-feet.
(c) Of this, 20 per cent is water (the connate water factor is said to be .20) and when this is taken out, 800 acre-feet of oil and gas remain.
(d) Of this total, 20 per cent is gas (the shrinkage factor is .20) and when the gas is taken out, 640 acre-feet of oil remain.
(e) All of this oil cannot be recovered. The recovery depends upon the reservoir drives and other factors. If the reservoir factor is 30 per cent, the recoverable reserve is 192 acre-feet. This equals 1,489,536 barrels.

Any reserve estimates quoted here or in previous chapters should be interpreted in the light of the factors considered above. It should be stressed that the technological and economic changes which affect the recovery factor through time might eventually either halve or double early estimates of the oil believed to be recoverable.

It has been estimated that at the end of 1946 a total of 157 million barrels of recoverable crude oil and condensate had been discovered in Alberta. Of this about 85 million barrels had been produced during the preceding 30 years. During 1947-56 more than 300 million barrels were found yearly on the average. The cumulative production reached 675 million barrels by the end of 1956. The first table on the facing page is indicative of the growth in reserves and production.

The output of crude oil in Alberta has increased more than twenty times within a decade, from a level of about 18,000 barrels per day in 1946 to almost 400,000 barrels in 1956. Production could have increased more if there had been greater market outlets. Actual production, prorationed by the Conservation Board, has run far below potential production since 1949. This potential is often referred to as the producibility of the oil wells of Alberta as defined by the MPR (maximum efficient permissible rate of production) formula of the Conservation Board. The second table on the facing page is indicative of restricted production.

Recoverable Crude and Condensate Reserves in Alberta, Excluding Associated Gas Condensate

in millions of barrels

Year End	Virgin Recoverable Reserves	Gross Addition to Reserves	Cumulative Production	Year End Reserve	Net Addition to Reserves
1946	157		85	72	
1947	271	114	91	180	108
1948	613	342	101	512	332
1949	1,046	433	121	925	413
1950	1,248	202	148	1,100	175
1951	1,520	272	194	1,326	226
1952	1,810	290	253	1,557	231
1953	2,245	435	330	1,915	358
1954	2,605	360	418	2,187	272
1955	3,034	429	531	2,503	316
1956	3,641	607	675	2,966	463

Source: PNGCB.

Actual and Potential Production of Crude Oil in Alberta, 1946-56

Thousands of barrels per day

	Actual Production	Potential Production*	Actual as Per Cent of Potential
Year 1946	18	18	100
1947	17	17	100
1948	29	29	100
1949	54	79	69
1950	74	146	51
1951	126	203	62
1952	161	262	61
1953	210	316	66
1954	240	342	70
1955	310	492	63
1956	393	684	58

Source: PNGCB.

*"Potential" as defined by the PNGCB.

During 1956 Alberta produced almost 144 million barrels of crude oil, about 84 per cent of a total Canadian production of 172 million barrels. The same year also saw the rapid rise in Saskatchewan output from 11 million barrels in 1955 to 21 million barrels in 1956, or 12 per cent of total Canadian output. Manitoba contributed nearly six million barrels while the Northwest Territories and Eastern Canada together accounted for the remaining one million barrels. The following table summarizes production data for Alberta in 1946-56:

Crude Oil Production Data, Alberta, 1946-56

Excludes natural gasoline and other liquid hydrocarbons

Year	Production millions of barrels	Number of Producing Wells	Value of Production at Well Head millions of dollars	Average Price per Barrel dollars	Average Production per Well Year	Average Production per Well Day
1946	6.7	523	12.7	1.90	12,800	35
1947	6.4	606	14.7	2.30	10,600	29
1948	10.5	714	33.6	3.20	14,700	40
1949	19.8	1,242	57.4	2.90	15,900	44
1950	27.2	1,995	80.6	2.97	13,600	37
1951	45.9	2,731	115.8	2.52	16,800	46
1952	58.9	3,661	139.7	2.37	16,000	44
1953	76.8	4,504	193.1	2.52	17,000	47
1954	87.6	5,068	227.9	2.60	17,300	47
1955	113.0	6,138	274.2	2.42	18,400	49
1956	143.9	7,390	355.2	2.47	19,400	53

Source: PNGCB.

The increases in production and its value are obviously large. Despite the introduction of prorationing there was an upward trend in production per well. The daily average production per well of 53 barrels in 1956 was more than four times the United States average of 12 barrels.

The progress in exploration, drilling and production has unquestionably been great since 1946. The industry has certainly not failed in discovering large quantities of oil. In fact, the average increase in reserves in each year has exceeded production several times over as fig. 36 reveals. Because pools can seldom be produced at an annual rate above 12 per cent (and often no more than six or eight per cent) of their remaining reserves, the petroleum industry looks many years ahead and strives constantly to assure adequate reserves for the future.

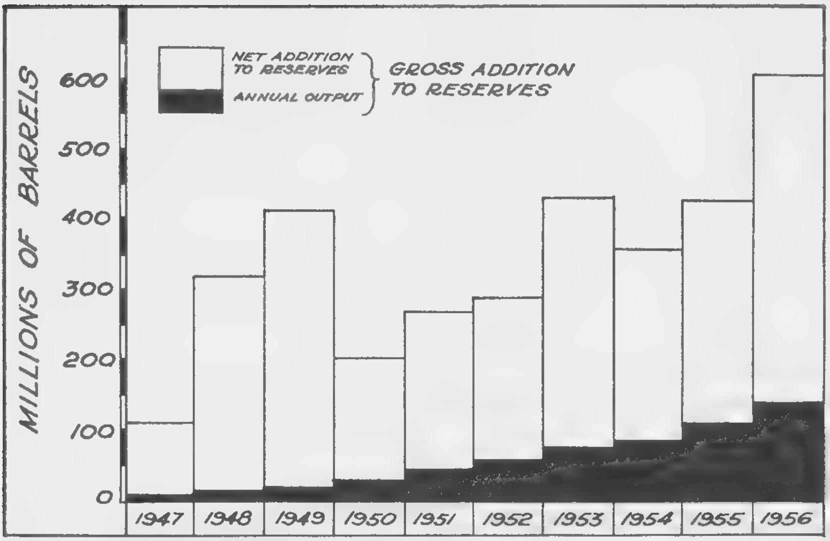


Fig. 36 Gross additions to reserves and annual production of crude oil in Alberta, 1947-56   Source: PNGCB

12

Expenditure on Exploration and Development

Large expenditures are required to develop the petroleum resources of a region. In Alberta the petroleum industry increased its cash outlays on exploration and development from an estimated $12 million in 1946 to nearly $400 million in 1956. All told the industry spent almost two billion dollars during the decade 1947-56.

A tangible result was the proving up of more than three billion barrels of oil as well as trillions of cubic feet of natural gas which will take decades to lift to the surface and to market. The revenue will have to equal several billion dollars over the years to recover the money spent, to pay production costs and to yield a return on the expenditures made. The two billion dollars spent is in the nature of a present value of revenue to be received in the future, discounted at a rate of return which cannot be estimated with accuracy until many years from now. Nobody knows at this time if the total venture of the petroleum industry in searching for oil in Alberta during the last decade will provide satisfactory returns.

What we do know is that during the decade in question, the expenditures led to a substantial growth of the Alberta economy. They provided employment for a rising number of workers, adding to both the population and income of Alberta. The employment and population effects will be summarized in a subsequent chapter. At this point, let us examine the types of expenditure, one by one, and assess the effects upon the income.

Several types of expenditure are involved in developing petroleum resources. They are set out in the opposite table which indicates approximately the estimated outlays on each during the ten years 1947-56.

The Effects of Administrative Expenditures

The petroleum industry has an administrative organization which co-ordinates the activities involved in the search for oil. A large part of administrative expenditures consists of the salaries and wages of managers, office personnel, management engineers and geologists, accountants, lawyers and diverse employees. In small oil companies the salaries and withdrawals of officers may be large in relation to total funds available and mergers usually effect economies in administration. Other overhead costs include rentals on office buildings, the construction of office buildings, the operation and maintenance of such buildings, property taxes, office equipment and supplies, consulting services and miscellaneous supplies.

Administrative expenditures rose from a little more than one million dollars in 1947 to almost $19 million in 1956. Altogether the industry spent more than $100 million during the decade 1947-56. How much income did this spending generate in Alberta?

About half of the annual expenditures consisted of salaries and wages paid to Alberta residents. After allowing for payments to Albertans for office rentals and construction, for materials and supplies bought in Alberta, for the cost of public utility services and for various other items, another estimated one fifth of administrative expenditures was paid to Albertans. About 70 per cent, then, was received in the first instance by Alberta residents. The rest went to non-residents, chiefly in payment of imported materials and supplies. There were annual variations during the decade, but the estimated proportion of Alberta income created immediately by administrative spending was close to seven tenths throughout.

In billions of dollars	
Administration	0.1
Surveys	0.2
Dry holes, exploratory drilling	0.2
Development drilling	0.6
Other development costs	0.2
Land acquisition	0.6
Total	1.9

Most of the funds for the expenditures on administration as well as on other activities came from outside the province. The proportion of non-resident funds to the total funds provided was an estimated four fifths or more during the decade. The expenditures of the petroleum industry in

Alberta consisted largely of the injection into the province of "foreign" funds.

This injection of spending from outside Alberta provided income in the first instance for people engaged in activities related to the petroleum industry. These people, however, as residents of Alberta, spent most of their receipts on a variety of goods and services. In doing so, other Albertans earned income and spent most of their receipts, creating further income. Altogether, this process led to the generation of a considerable flow of income.

A great limitation imposed upon the generation of income in Alberta is the high ratio of imports in goods and services purchased by residents. In other words, a large part of the funds provided by non-residents goes back to regions outside Alberta. The import content of goods and services purchased by Albertans averages more than 40 per cent. Alberta is in high degree what the economists call an "open economy" with comparative advantages in the production of agricultural and petroleum products. The province exports a high proportion of its output of such products to pay for imports. Investment by non-residents also provides funds for the same purpose.

In millions of dollars	1947	1956
a. Estimated administrative expenditure	1.2	19.0
b. Estimated portion financed by non-resident funds	0.9	16.0
c. Primary regional income created (70 per cent of b)	0.6	11.0
d. Ultimate regional income generated (c multiplied by 2.3 in 1947 and by 2.0 in 1956)	1.4	22.0

Suppose that one million dollars is spent on the administration of the exploration and development activities of the petroleum industry in Alberta. Out of this expenditure, an estimated $700,000, or 70 per cent, is received by Alberta residents. The recipients spend nearly all of this income. Much of their expenditure will be on imported goods and services, leaving about $400,000 as receipts of a second group of Alberta residents. The latter spend most of their receipts and again a large proportion pays for imports. A little more than $200,000 would accrue to a third group of Alberta residents. After three rounds of spending, then, an income exceeding $1,300,000 has been generated, almost twice the

estimated $700,000 first received by Alberta residents which may be called primary income.

Various estimates made suggest that the ratio of generated income to primary income over a period of one year in Alberta was approximately two during the decade. In the case of administrative expenditures, one million dollars spent in the province created an estimated $700,000 of primary income which in turn generated an estimated additional $700,000 of income. The total regional income generated by the expenditure would then be about $1,400,000.

The opposite table indicates the rising importance of income in 1947-56 from expenditures on administration in Alberta and shows the successive steps in making estimates.

Expenditures on Surveys

Most survey work in Alberta is undertaken on a seasonal basis. It has been found to be very costly and almost physically impossible to survey adequately the muskeg country in the northern part of the province during the summer. Consequently geophysical crews work in the plains country of the three prairie provinces during the summer and fall months. By November, with the muskeg country frozen enough to permit relatively easy movement, the crews move north and the number active in Western Canada increases. For example, about 165 geophysical crews were active in Western Canada during the winter of 1955-56, while by June, 1956, the total declined to 112. Winter operations and higher overhead resulting from essential fluctuations in activity make geophysical surveys costlier than in most areas of the United States.

Most survey work is done by geophysical contractors, many of which are American with branch offices in Alberta. Most of them have established their western Canadian head offices in Calgary, with a few in Edmonton and Regina; there are many branches and field offices in Edmonton and other centres. These contractors employ a variety of skilled personnel, including exploration drilling contractors and independent geological and geophysical consultants. In June, 1956, 26 geophysical contractors supplied 84 out of the 112 crews active in Western Canada, about three quarters of the total. Eight oil companies had their own as well as contracted crews in the field. For example, Imperial Oil had seven of its own crews and 13 contracted crews in the field, Texaco Exploration had four and ten respectively, and Canadian Gulf (now part of British American) had seven and five. Altogether, 27 companies reported 97 crews active in Western Canada while undisclosed companies had 15 crews at work.

Survey work, then, is undertaken by a small percentage of the oil companies with operations in Alberta. Imperial, Texaco, Gulf, Mobil, California Standard and Shell had three fifths of all crews engaged in Alberta and more than half of the western Canadian total. To do geophysical work effectively and economically, a company needs to explore relatively large tracts of land which the small companies usually do not hold. Spending on exploration is a speculative venture in which the risks need to be spread over several areas. Every dollar spent on fruitless exploration has to be charged against revenue from production in successful areas. The small companies can hope to benefit from knowledge derived by the surveys undertaken by the large and they can buy prospective petroleum properties accordingly. They can also obtain farmouts from the large or they may reverse this process by farmouts to the large. Some of them employ their own geologists who interpret geological and geophysical data; some rely upon independent geological and geophysical consultants as sources of information. Many companies, both large and small, also employ scouts whose duties are to obtain geological and geophysical information by their observations of exploration and drilling crews in the field.

The expenditures on geological and geophysical surveys have been substantial since 1946. Cash expenditures on surveys in Alberta totalled an estimated $12 million for the 30-year pre-Leduc period of 1917-46 while the total for Western Canada is estimated at about $14 million. During the post-Leduc decade of 1947-56, an estimated $237 million was spent on surveys in Alberta and about $135 million in Western Canada.

To arrive at these estimates it was necessary to take into account the cost of putting survey parties in the field. A seismic crew usually consists of about 20 men equipped with four trucks. One truck carries the seismograph, a second a light portable drilling rig, a third carries water for the rig, and the fourth carries dynamite. The crew drills shot holes which may be up to 100 feet deep; dynamite is inserted in the hole and exploded. The seismograph records the travel time and other data on the sound waves which are shot downward by the explosion and then reflected back by the rock. From these data a map of the subsurface conditions can be worked out.

In 1946 it cost, on the average, about $13,000 per month to keep a seismic crew in the field. In 1956 the cost was more than twice this amount. In northern operations, the cost is now at least $30,000 per month and in many cases it is more. It is not unusual to have to spend $40,000 or even $50,000 per month to operate a crew in northern Alberta during the winter season.

Gravitymeter and magnetometer crews are small; their cost, on the

average, was about $10,000 per crew-month in 1956. A core-drill crew cost nearly $20,000 per month in the same year. A surface or geological party usually consists of only two or three men who may travel by automobile to the territory to be explored and then proceed on horseback or on foot. They are equipped with light equipment such as slide rules, compasses and plane tables. The cost per "party-month" may vary from a few thousand dollars per month to $20,000 per month, depending upon the size and equipment of the party.

The largest expense in survey work consists of salaries paid to geologists, geophysicists and their crews. These workers are resident in Alberta during survey operations, no matter where they may have come from originally. It is of interest to note that less than four per cent of the employees of the petroleum industry in Western Canada are citizens of the United States. The large companies which have widespread international operations make it a point to hire and to train regional residents wherever this is at all possible.

The expenditures of survey workers on consumption goods have a marked effect upon the level of economic activity of the cities and towns in the vicinity of their operations and also upon that of the communities in which their families live. The spending of crew members and their families, then, is practically all confined to Alberta centres.

Data of the Alberta Bureau of Statistics and information obtained in interviews with contractors indicate that about 45 per cent of total expenditure on exploration went to pay wages and salaries of crews, professional staff and administrative employees. A seismic crew uses about $3,000 worth of dynamite per month, and this item is supplied regionally by the plant of Canadian Industries Limited. All told, an estimated 10 per cent of total cash expenditure on surveys went to workers in Alberta manufacturing, wholesale and retail establishments supplying the survey industry. Another two per cent or so ultimately found its way to wage and salary earners in the fuel and electricity industry. About one per cent was paid out in taxes, licences and fees to the municipal and provincial governments. A further two or three per cent went to Alberta proprietors of and workers in office buildings and miscellaneous workers in various trades. All this adds up to about 60 per cent of total cash expenditure on surveys. The balance leaked out to other regions to pay for trucks, seismic equipment, various kinds of materials and supplies, interest on borrowed money and dividends. The percentage was considerably higher during the first few years of the decade before explosives and other supplies came to be provided regionally. This was taken into account in making the estimates of income accruing to Albertans set out in Table IV, page 141. Account had also to be taken of survey activities in the Peace River Block of British Columbia, a region which is served largely by Edmonton

and whose residents make important contributions to Alberta income.

Expenditures on surveys rose from an estimated $2½ million in 1947 to an estimated $30 million in 1956. The following table shows the effects upon income in Alberta in 1947 and 1956:

In millions of dollars

	1947	1956
a. Estimated expenditure on surveys	2.5	30
b. Estimated portion financed by non-resident funds	1.5	24
c. Primary regional income created (50 per cent of b in 1947 and 60 per cent of b in 1956)	0.8	15
d. Ultimate regional income generated (c multiplied by 2.3 in 1947 and by 2.0 in 1956)	1.8	30

As in the case of administrative expenditures, survey expenditures made a large contribution to personal income in Alberta in 1956 in contrast to the small one of 1947.

Expenditures on Drilling

Once an oil explorer decides to drill for oil in a specific location he obtains the services of a drilling contractor, unless he happens to have his own rigs and crews. The two common methods of drilling are the cable-tool and the rotary.

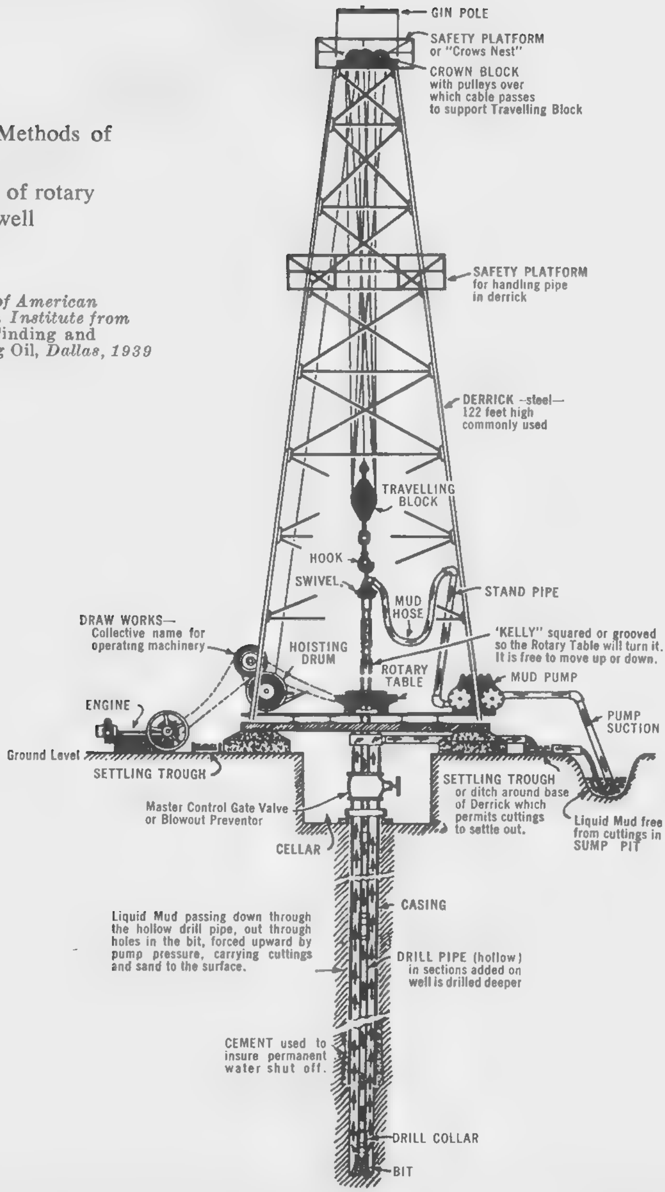
The cable-tool method involves the use of a bit suspended at the end of a rope or chain. The bit is punched into the hole to crush rock which is taken out by bailing with a hollow tube or pipe with a valve at the bottom end. This rather crude method prevailed during the nineteenth century but has become increasingly uncommon in the twentieth with the development of rotary drilling. In the United States, the cable-tool method is still used to drill about one tenth of all wells drilled annually; in Alberta cable tools may be used occasionally, but only for "spudding in"; they are inadequate to cope with the deep drilling so often required. A cable-tool rig consists of a derrick, a walking beam for raising and lowering the drilling tools, bailing equipment for lifting out cuttings, equipment for handling casing and for pressure control and power plant.

The rotary method, evolved since the turn of the century, prevails in Alberta and North America generally. A rotary drilling rig is suspended by and enclosed by a steel derrick to raise and lower tools and pipe. The

Fig. 37 Methods of drilling

Diagram of rotary drilling well

Courtesy of American Petroleum Institute from the book Finding and Producing Oil, *Dallas, 1939*



"DRAW WORKS"—the collective name for the hoisting drum, shaft and clutches and other operating machinery. Power is received from the engine. The ROTARY TABLE is driven by chain from the draw works and rotates the hollow drill stem, which drills the well. The DRILL STEM, consisting of drill pipe, drill collar, and bit, is raised or lowered into the well by a cable which is wound on the hoisting drum and passes through a series of pulleys in the crown block. CASING, or lining, for the well is raised or lowered by the same method. CUTTINGS are removed by pumping liquid mud, obtained from a sump pit, down through the hollow drill pipe. It passes out through holes in the bit and, forced upward by pump pressure, carries the cuttings to the surface. Here the liquid passes through settling troughs, in which the heavier particles sink to the bottom. The cleansed mud flows back into the sump pit and is used again, not only for removing cuttings, but as a plaster on the walls of the well to prevent caving until the casing is set.

derrick is usually from 100 to 200 feet high. The drilling bit is attached to a long shaft called the drill stem which is rotated in a table by power from a steam or internal combustion engine. The bit cuts its way by rotation through rock formations. The drill stem is hollow and drilling fluid is pumped down the stem and into the well through holes in the bit.

Beside the derrick and the hoisting equipment there is a drilling string, a rotary table to turn the drilling string, pumps and hose for circulating the mud, equipment for cementing and perforating casing, equipment for testing cores and fluids found, pressure controls and a power plant.

It is an impressive sight to see a derrick stacked with literally miles of pipe and a skilful crew either pulling up or running down the pipe. Changing the bit becomes a long and arduous task, requiring hours, when depths of six, eight, ten and more thousand feet are reached. If rock formations are very hard, drilling is slowed up greatly as bits have to be changed often relative to the footage achieved.

The hole is lined with lengths of steel pipe called casing which are strung together in successive links. Cement is used to provide a "shoe" for the casing and to seal off water, oil or gas.

Casing consists of steel pipes in lengths of 30 feet or more which are larger in diameter than the drill pipe. They are also lighter in weight than the latter. The hole drilled is usually larger at the top than farther down because a reduction in size must be made each time a string of casing is cemented to shut off fluids. At the top the hole is usually more than a foot in diameter, or even greater, if very deep drilling is anticipated. As drilling proceeds, the hole may be reduced until it is only a few inches in diameter. In exploratory drilling, casing is usually not set except for the first few hundred feet near the surface. Further casing, however, will be undertaken if there is danger of a cave-in or if oil, gas or water in significant quantities is encountered. Of course, if oil or gas in commercial quantities is found, the hole will be cased for the full distance to the pay zone.

Drilling is a continuous operation which usually demands the services of three crews working eight-hour "tours" in rotation. Each crew consists of five men, driller, derrick man, cat head, lead tong and pipe racker. The driller is in charge of a crew while a "toolpush" supervises the crews at one or more wells. The men working on a rig are generally called "roughnecks", a term of which oil workers are inordinately proud. In addition to the men actually at work on the rig there are truckers, water-haulers and other supply workers who may serve one or more rigs. A skilful drilling crew works with a high degree of co-ordination, each member anticipating the actions of the others. A zeal for making drilling time and other records pervades crews who have built up tradition and *esprit de corps*. These records are often reminiscent of those kept in football for

yardages or first downs gained or of the innumerable ones kept in that most statistical of sports, baseball.

The expenditures on drilling and development may be divided into three categories.

First, some wells were dry holes and capped gas wells. During 1947-56 an estimated total of $250 million was spent in Alberta on drilling failures and capped gas wells. The annual expenditure rose from about $7 million in 1947 to an estimated $35 million in 1956. By comparison, an estimated $380 million was spent on drilling dry holes and capped gas wells in Western Canada during the decade. The average cost for Alberta of drilling a dry hole fluctuated between $60,000 and $80,000 during 1947-56. Variations in costs from year to year arose from differences in depths and formations penetrated and from changes in drilling techniques. There was no particular upward trend in the average cost despite the greater depths of wells and higher wages and prices paid for drilling materials and equipment in 1956 than in 1947. Increased penetration rates and added efficiency prevented any material rise in the dollar expenditure per well.

Second, many wells were producers. Most of these were drilled in the course of developing fields, but some were productive wildcats. Additional expenditures are required for a producing well. These are made to pay for perforation, acidizing or shooting or sand fracturing, casing and tubing. The average cost in Alberta of completing a producing well, including the drilling, varied greatly during the decade because of differences in average well depths, in formations penetrated and costs of materials and equipment. In 1947 when many shallow wells (averaging about 2,000 feet) were completed in the Lloydminster and Vermilion fields, the average cost was not much over $40,000. In 1948 when Leduc completions at depths of more than 5,000 feet predominated, the average rose to more than $60,000. In 1956 when Pembina completions were dominant, the average cost approached $100,000. Little could be done to reduce costs because the additional expenditures involved mainly the purchase of casing, tubing and other equipment which rose in price quite markedly.

The total expenditure on drilling producers (we shall call it development drilling) in Alberta was an estimated $560 million for 1947-56 or nearly 30 per cent of the total new investment on production. The annual level of expenditure rose from an estimated $5 million in 1947 to an estimated $140 million in 1956. The Alberta total for the decade was more than three quarters of the western Canadian total.

Third, to put a well on production, expenditures are required for lifting and pumping equipment, flow lines, separators and tanks. These expenditures are often termed "other development costs" and they totalled an

estimated $200 million in Alberta for 1947-56, about three quarters of the total for Western Canada.

Table III summarizes the total new investment in petroleum production. In only one year did the expenditures fall. That was in 1953 after Leduc and Redwater had been developed and before the Pembina field came in. Even in 1956 when there was intensive activity elsewhere in Western Canada, the Alberta proportion of expenditures in the four provinces was an estimated 70 per cent. Figure 38 sets out graphically the expenditures in Alberta during the decade.

Table III

Estimated New Investment in Petroleum Production in Alberta, 1947-56*

In millions of dollars

Year	Administration	Acreage	Surveys	Dry Holes	Development Drilling	Other Development Costs	Total
1947	1	5	2	7	5	3	23
1948	3	12	7	11	15	10	58
1949	6	32	14	19	31	22	124
1950	8	57	22	18	36	14	155
1951	9	44	27	32	50	14	176
1952	11	57	37	34	60	20	219
1953	11	57	36	32	49	19	204
1954	18	104	33	28	61	23	267
1955	19	100	29	34	115	25	322
1956	19	120	30	35	140	47	391
Total for Decade	105	588	237	250	562	197	1,939
Percentage of Total	5	31	12	13	29	10	100

*Includes natural gas.

Sources: Estimated by the writer from data obtained from the DBS, ABS and the petroleum industry.

Note: New investment for our purposes includes all expenditures by the industry on the development of the petroleum resources of Alberta. Some definitions are more restrictive, omitting acreage costs, expenditures on surveys and even expenditures on dry holes because these expenditures do not result directly in production.

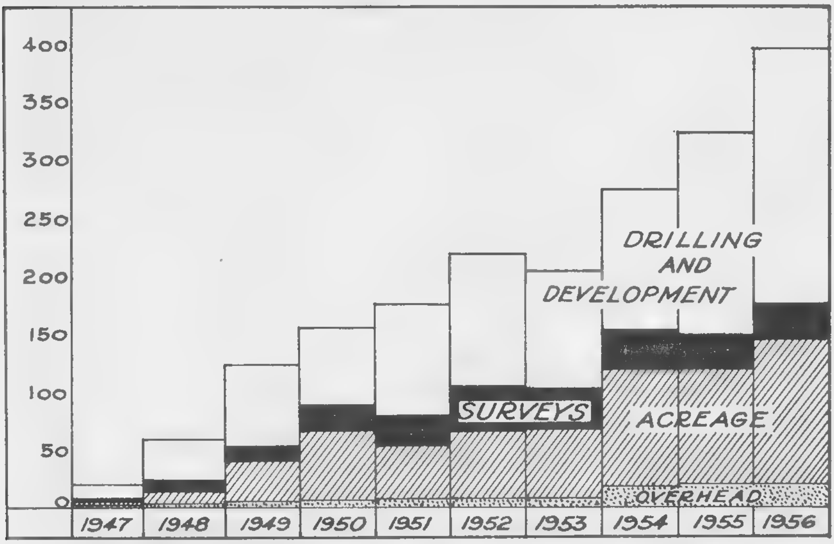


Fig. 38 Estimated new investment in petroleum production in Alberta, 1947-56 (millions of dollars)

Income From Drilling and Development

A large part of the expenditures on drilling and development in Alberta is disbursed to non-residents. This includes a multitude of equipment and materials. A drilling rig is a unit consisting of 150 to 200 or more tons of materials, including the drill pipe but excluding casing. Most of the equipment is imported from the United States; some items come from Eastern Canada and even Europe. Among the materials used, most of the acid, mud and cement casings are imported from the United States with a fraction coming from Eastern Canada. Most of the cement and all the fuel and electricity used are produced in Alberta; to a large extent, so are grease, oil and explosives. Trucking and freighting, payments for surface rights, some overhead items and regional taxes call for expenditures to Albertans. Finally, wages and salaries paid are practically all regional income. Part of the expenditures on imported items accrues to Alberta residents since supply houses maintain staffs of service men and salesmen in Alberta and since regional transportation and wholesaling services have to be utilized. For example, firms supplying drilling bits have administrative offices in Alberta and they have service personnel which travel widely to well locations. The result

In thousands of dollars

	Expenditure In Alberta	Expenditure Outside Alberta	Total
1. Labour and contractors' margins:			
(a) Drilling	18.0	2.0	20.0
(b) Cementing services, core analysis, drill stem tests, welding casing and electrologging	1.6		1.6
(c) Consulting engineer	1.6		1.6
(d) Road work, caterpillar work, surveying site and miscellaneous	2.2		2.2
2. Materials:			
(a) Surface casing, 300′ 10¾″	0.6	1.4	2.0
(b) Diamond coring, 80′	0.3	0.5	0.8
(c) Electrolog supplies	0.2	0.2	0.4
(d) Scratchers and centralizers	0.1	0.2	0.3
(e) Displacement oil	0.6	0.2	0.8
(f) Mud conditioner	0.6	1.0	1.6
(g) Cement	0.8	0.6	1.4
(h) Fuel and power	0.9	0.7	1.6
(i) Grease, oil, explosives and other materials	1.0	0.4	1.4
3. Equipment:			
(a) Depreciation of rig and drill pipe	1.0	2.6	3.6
(b) Bits	2.0	3.0	5.0
(c) All other	0.4	0.6	1.0
4. Other:			
(a) Trucking and freight	2.0	1.0	3.0
(b) Insurance	0.2	0.8	1.0
(c) Taxes	0.2	0.1	0.3
(d) General overhead	1.0	0.5	1.5
(e) All other costs	2.0	2.0	4.0
Total	37.3	17.8	55.1

Note: Alberta expenditure content is that which was spent on the non-import portion of goods and services. For example, although nearly all the cement was bought in Alberta, much of the machinery and equipment of Alberta cement plants were imported and so were certain supplies. Similarly, there is some Alberta income in items imported from handling, transportation and servicing facilities.

is the accrual of wages, salaries, travelling expenses and many other items to the region.

The task of estimating the percentage of accrual of income to Alberta residents from drilling expenditures was no mean one. The costs fluctuated through the decade, leading to variations in the percentages of expenditure accruing to Albertans. The increased efficiency achieved in drilling techniques throughout the decade also had a bearing on the estimates. We shall work through an example to indicate the procedure involved.

Exploratory Drilling

Let us suppose that we drilled a dry hole in the Leduc-Woodbend field to a depth of about 5,200 feet to a typical D-2 formation. The table opposite indicates the approximate cost as well as the proportions of expenditure accruing to Alberta residents and to non-residents.

From the data in the table it appears that of the estimated cost of $55,000, about $37,000, or two thirds accrued as income to Alberta residents while the other third accrued to non-residents. There were variations for different wells and in different years, but the proportions suggested by our example were fairly good approximations for the decade. Wages, salaries and contractors' margins together made up a little more than two fifths of the total cost of drilling dry holes.

In thousands of dollars

	Expenditure In Alberta	Expenditure Outside Alberta	Total
1. Total for drilling as per previous table	37.3	17.8	55.1
2. Completion costs:			
(a) Jet perforation	0.3	0.2	0.5
(b) Acidizing	0.8	1.0	1.8
(c) Casing, 4,900′ 7″	3.3	9.3	12.6
(d) Christmas tree	0.3	0.7	1.0
(e) Tubing, 5,200′ 2⅞″	1.2	3.0	4.2
(f) Miscellaneous	1.0	1.0	2.0
Total	44.2	33.0	77.2

Development Drilling

Development drilling expenditures essentially include the costs of drilling as shown in the previous table plus the outlays on completing wells. To complete a well, casing and tubing have to be set down to the producing horizon, acidizing or shooting have to be undertaken and a "Christmas tree" (producing head) installed. Let us now assume that the dry well whose drilling costs were broken down in the previous table becomes a producing well; in other words, we find oil. Then the table has to be extended to include completion costs (see p. 139).

The import content in development drilling expenditures is greater than in dry hole expenditures mainly because thousands of feet of casing and tubing are needed to reach the producing horizon. Of the total $77,000 spent on our well, about $44,000 accrued as income to Alberta residents,

In thousands of dollars

	Expenditure In Alberta	Expenditure Outside Alberta	Total
1. Production equipment:			
(a) Float shoe and collar, pump shoe and gas anchor	0.1	0.1	0.2
(b) Bottom hole pump	0.1	0.2	0.3
(c) Sucker rods, 5,100′	0.5	2.1	2.6
(d) Pump jack and counter weights	1.2	3.8	5.0
(e) Motor and controls	0.3	0.7	1.0
(f) Flow line, 700′	0.4	1.0	1.4
(g) Installation of pump	0.5	0.2	0.7
(h) Separator	1.4	3.6	5.0
(i) Two 500 bbl. tanks	0.9	2.7	3.6
(j) Installation of tanks	1.0	0.2	1.2
(k) Fittings and piping	1.0	3.0	4.0
(l) Installation of fittings, etc.	0.9	0.1	1.0
(m) Road work, fencing and miscellaneous	1.0	1.0	2.0
Total, production equipment	9.3	18.7	28.0
2. Total for drilling and completion as per previous tables	44.2	33.0	77.2
Total, all costs	53.5	51.7	105.2

Table IV

Income Generated in Alberta by Expenditures on Petroleum Exploration and Development, 1947-56

In millions of dollars

Year	Administrative Overhead	Surveys	Dry Hole Drilling	Development Drilling	Other Development Costs	Total
1947	1	2	6	3	1	13
1948	3	7	12	14	6	42
1949	7	13	21	30	13	84
1950	8	20	18	34	8	88
1951	10	26	34	46	8	124
1952	13	34	36	54	10	147
1953	13	36	34	44	10	137
1954	21	34	30	54	12	151
1955	22	29	36	100	14	201
1956	22	29	40	126	26	243

Note: The estimates are based on the expenditures set out in Table III, the estimates of their regional content, adjustments for the ratio of non-resident funds and multiplication by a generative ratio falling from 2.3 to 2.0 during the decade.

or about 57 per cent. About two fifths of the $44,000 accruing to residents went to employees, proprietors and suppliers (in part only) of drilling contracting firms; this fraction tended to shrink somewhat during the decade. The remaining three fifths or so of the $44,000 accrued to Alberta residents employed in a miscellany of activities.

Other Development Costs

It remains to bring our well into production. To do this, lifting equipment, flow lines, separators and tanks have to be provided. The expenditures on these items are usually termed "other development costs". Again, we shall extend the previous table to take the installation of producing equipment into account. Suppose that the well has to be placed on a pump to produce. Then the extended table is as shown opposite.

The installation of equipment resulted in an additional expenditure of $28,000 of which only an estimated $9,000, or one third, accrued to

Alberta residents as income. Most of this $9,000 would go to service contractors and supply houses in Alberta. The import content for this activity is clearly very large. The total cost of our well turned out to be about $105,000 of which an estimated $53,000, roughly half, accrued as income to residents.

There were, of course, some variations in the total cost of drilling wells throughout the decade and great variations in different areas. Many shallow wells in the plains regions cost no more than $50,000 to drill, complete and bring in, while some dry holes in the foothills cost more than one million dollars.

Table IV summarizes the income effects of not only drilling and development expenditures, but also of administrative and survey outlays. The income effects of expenditures on land acquisition are dealt with in a subsequent chapter.

The income generated in Alberta from the five types of expenditure on exploration and development was an estimated $13 million in 1947, not quite two per cent of the personal income of the province in that year. In 1956 the income generated was almost 20 times as large in current dollars and equalled about one sixth of the total personal income of the province of Alberta. Exploration and development activities have come to play an important part in furnishing the livelihood of Alberta residents.

13

Refineries

Before Leduc practically all of Alberta's refinery capacity was concentrated in the Calgary area. The only exceptions were the small heavy-crude Excelsior and Gold Standard refineries in Lloydminster and Wainwright respectively. Petroleum products were shipped into Edmonton and throughout central and northern Alberta from Calgary.

With the discovery of Leduc it made little sense to maintain this state of affairs. Imperial Oil began to plan the construction of a refinery at Edmonton shortly after the Leduc discovery. It was estimated that it would take at least three years to build one because it was difficult to obtain steel during the postwar years. As in the case of the Nisku pipe line, the company found a "second-hand" unit, the refinery at Whitehorse in the Yukon Territory, closed down after the war. It was bought promptly from the United States government for one million dollars.

The refinery was dismantled; the parts were labelled to provide direction for the construction crews in Edmonton. It was no easy task in the darkness of the Yukon winter; frequent high winds also made it hazardously difficult to bring down the towers, 80 to 150 feet in height. Altogether, about 100 men worked at the dismantling job. Most of the parts were shipped by trucks from Whitehorse to Dawson Creek along the Alaska Highway, a distance of more than 900 miles. A fleet of the ten largest trucks in the world was brought from California along with 20 drivers. The trucks made more than 25 round trips each, carrying loads varying from 40 to 60 tons. At Dawson Creek, the parts were unloaded and shipped to Edmonton by rail. Some bulky units went by rail to Skagway, Alaska, then by sea to Vancouver, and then by rail to Edmonton.

At Edmonton about 150 men cleared the ground for the refinery and assembled the parts. In the early spring of 1948 a tank farm of twelve large storage tanks was completed. In May the first 80-foot tower was up and shortly afterward came the crude unit furnace and its tall stack.

In June trucks began to haul crude oil from the Leduc-Woodbend field at an initial rate of 2,000 barrels per day; by July they were making 100 trips a day to deliver 4,000 barrels to fill the tanks. The water intake on the North Saskatchewan River was built during the spring and foundations for the pump house prepared. Natural gas lines were laid from the main lines of Northwestern Utilities to provide fuel. Power lines and water mains were provided. The crude distillation plant was completed by June and test runs were made. In July the official public inaugural ceremony was held and by August, 1948, the whole unit, with a capacity of 6,000 barrels per day, occupying 100 acres, was on stream. Edmonton had acquired its first refinery and a market for Leduc crude had been created on the doorstep of the field.

The whole operation was completed in 17 months and ultimately cost $8.7 million, at least as much as a new refinery would have cost. However, it provided a refinery a year and a half before a new one could have been built. The Whitehorse plant is still an efficient part of the present much-expanded Imperial Oil refinery at Edmonton. During 1948 the Imperial Pipe Line Company completed an 18-mile pipe line from Nisku to the refinery and the hauling of crude oil by trucks ceased.

Soon after the ex-Whitehorse refinery was put into place, Imperial Oil began a program of refinery expansion at Edmonton. The company added 10,000 barrels of daily capacity in 1949 and built up the plant gradually to a daily capacity of 25,000 barrels. It is a complex plant with facilities for fluid catalytic cracking, thermal cracking, catalytic reforming, ketone dewaxing, phenol extraction, hydroforming and lubricating oil production. The lubricating oil plant was constructed at a cost of $13 million and opened in November 1955 to make a variety of lubricants for the western Canadian market; it has a capacity of 2,000 barrels per day. The refinery at Calgary was expanded somewhat after the Leduc discovery, from 6,300 barrels per day to 9,200 barrels per day. Currently, a large new plant is planned. The present facilities are largely designed for thermal cracking. Altogether, Imperial Oil now has a little more than two fifths of the refinery capacity of Alberta.

The British American Company was the second to complete a refinery in Edmonton, and it was officially opened on June 27, 1951, by Mr. E. C. Manning, Premier of Alberta. The company chose to build a new refinery at Edmonton rather than to expand its Calgary unit largely because of the growing availability of crude oil and the expanding market in the Edmonton region and the north. The refinery, with a capacity of 5,200 barrels per day, was a combination unit with catalytic and thermal cracking, delayed coking, gas recovery and crude topping sections. The orthoflow converter installed was Alberta's first catalytic cracking unit which facilitated greatly the production of high-octane gasoline. The

capacity of the plant was eventually increased to 7,000 barrels per day. Nearly all the crude used comes in by pipe line. The Calgary plant was expanded before 1951 from a capacity of 5,500 to 7,200 barrels per day. It has facilities for thermal cracking and catalytic reforming. Most of the crude moves into this plant by rail from various fields in Alberta and the rest from Turner Valley by pipe line.

In late 1951, the McColl-Frontenac Company completed its first western Canadian refinery at Edmonton. It was built with an initial capacity of 5,500 barrels per day and it incorporated the latest features of the technology of petroleum refining. Resembling somewhat the plants of the other two companies, the equipment consisted of a combination unit with facilities for fluid catalytic cracking, thermal cracking, catalytic polymerization, delayed coking and catalytic reforming. Crude oil moves into the plant by pipe line from the fields around Edmonton. By the end of 1956, the plant was doubled in capacity to 11,000 barrels per day.

The Anglo-American Exploration Company acquired the Hartell refinery of the Turner Valley Oil and Gas Company and expanded its capacity from 2,200 to 3,000 barrels per day. In 1956 it was manufacturing some gasoline with the highest octane rating in Alberta, a distinction which is usually temporary since refining companies make it a point to wrest this kind of leadership from each other.

During the late 1940's the Excelsior Refining Company expanded its refinery at Lloydminster and the Husky Oil and Refining Company built a unit there. The Excelsior unit now has a capacity of 3,800 barrels per day and the Husky has one of 8,500 barrels per day. These two refineries specialize in processing "heavy" crude supplied from the surrounding oil fields by truck. The gravity of the oil ranges from 12° to 18° API in contrast to the 30° to 40° API crude processed by the Edmonton refineries. The sulphur content, which is only a fraction of one per cent in the Leduc and Redwater crudes, is from three to four per cent in the Lloydminster crude.

Two other refineries in Alberta process heavy crudes. One is operated by the Wainwright Producers and Refiners Company at Wainwright. Its new 3,000-barrel-per-day unit was opened officially in October, 1956. The other is at Bonnyville and is operated by the Bonnyville Oil Refineries Company. It is the smallest in the province with a capacity of 1,100 barrels per day. The Wainwright refinery obtains heavy crudes varying from 15° to 23° API with a sulphur content between two and four per cent from the Chauvin field by rail and from the Wainwright and Baxter Lake fields by truck. The Bonnyville refinery is served by trucks from adjacent fields with 14° API crude which contains almost four per cent sulphur.

The Peace River region obtained its first refineries in 1956. The North

Table V

Crude Charging Capacity of Refineries in Western Canada, 1946, 1951 and 1956

Barrels daily at year ends

	1946	1951	1956
Alberta			
1. Anglo-American Exploration Ltd. (Refining Division), Hartell	2,200	2,500	3,000
2. Bonnyville Oil Refineries Ltd., Bonnyville			1,100
3. British-American Oil Company:			
a. Calgary	5,500	7,200	7,200
b. Edmonton		5,750	7,000
4. Excelsior Refineries, Lloydminster	1,000	2,500	3,800
5. Husky Oil and Refining Ltd., Lloydminster		7,500	8,500
6. Imperial Oil Limited:			
a. Calgary	8,300	9,200	9,200
b. Edmonton		22,600	25,000
7. McColl-Frontenac, Edmonton		5,500	11,000
8. North Star, Grande Prairie			2,500
9. Wainwright Producers and Refiners, Ltd.	300	300	3,000
Total, Alberta	17,300	63,050	81,300
Manitoba	4,750	20,450	29,700
Saskatchewan	18,275	40,300	71,000
British Columbia	24,900	28,350	61,500
Northwest Territories (Norman Wells)	850	1,250	1,250
Total, Western Canada	66,075	153,400	244,750
Eastern Canada	177,100	259,500	408,800
Total, Canada	243,175	412,900	653,550

Sources: *Daily Oil Bulletin*, *World Oil*, DBS, and other sources.

Star Oil Company completed one at Grande Prairie with a capacity of 2,500 barrels per day. Truck transport will be used to deliver crude oil from the Sturgeon Lake and Little Smoky oil fields. The Excelsior Refin-

eries Company built a refinery at Dawson Creek, just inside British Columbia, with a capacity of 2,000 barrels per day.

Refinery construction reached its peak in Alberta and Western Canada during the years 1950 and 1951. It was in those years that Edmonton attained its present stature as a notable refinery centre. Substantial additions were also made in the Saskatchewan refinery centres, Regina and Moose Jaw, and the refining capacity of Manitoba was increased greatly by the completion of an Imperial Oil refinery at East St. Paul, near Winnipeg, in 1951. There were also substantial additions to capacity in British Columbia.

At the end of 1946, Alberta, with less than seven per cent of Canada's population, had about seven per cent of Canadian refinery capacity. In 1956, with a little more than seven per cent of Canada's population, the province had about 12 per cent of Canadian refinery capacity. Alberta capacity rose from roughly 17,000 barrels per day to more than 80,000 barrels per day in 1946-56, nearly a fivefold increase (see Table V). Nowhere in Canada did capacity rise so rapidly percentagewise during the postwar decade as in Alberta. A considerable volume of products is exported to other provinces, about one fifth of the total annual output.

In view of the great growth in refinery capacity in Alberta since 1946, further large additions appear unlikely. Additions will be made to keep pace with the growth of regional population and the regional demand for petroleum products. Another factor militating against large expansions is that continuous modifications can be made to make existing units more efficient and versatile; much can be done by skilful operation to obtain extra capacity out of an existing plant.

Western Canadian capacity nearly quadrupled in 1946-56 (see Table V). This expansion provided an increasing outlet for Alberta crude during the decade. Large increases in eastern Canadian refining capacity also took place (see Table V) and these became of significance to Alberta crude oil producers after the Interprovincial Pipe Line was built.

The Marketing of Petroleum Products

Refineries turn out many products which are handled, transported and sold in different ways. Gasoline is the main product and also the one most familiar to people. Gasoline and other products produced by refineries are usually handled by bulk dealers, both independent and those parts of integrated operations. First, there are the salaried bulk plants which are supplied mainly by tank car from the refinery. They

carry on a wholesale trade in all products, delivering usually by tank truck, but also, as in the case of packages, by regular trucks to retailers, consumers and industrial markets. The large refining companies in Alberta have bulk plants in the main centres such as Edmonton, Calgary and Lethbridge. Second, there are commission agencies which are supplied from refineries mainly by tank car, although some supplies come by tank truck from salaried bulk plants. They carry all products and deliver to the retail trade and to consumers. The commission agency is used where gallonage is small; their chief accounts are in the farm trade business. Third, there are the farm trade dealers who are supplied by tank truck from salaried bulk plants or from commission agents, depending on distance. They supply to retail outlets and also sell to the farm trade; they usually have pumps and sell products to the surrounding territory in drums. This is a combination of wholesale and retail marketing and is generally used in place of the commission agency where volume is insufficient to justify the establishment of that form of outlet. Everyone is familiar with the filling station, the typical retail outlet for gasoline and other petroleum products. Garages, hardware, general and other stores may also sell these products.

Investment in Refining

Refinery building costs are currently estimated to run from $1,000 to $1,500 per barrel-day of throughput. Without allowing for cost differences arising out of size of refinery, this would mean that a very small refinery with a capacity of 1,000 barrels per day would cost one million dollars or more to construct while one of an intermediate size with a 10,000-barrel-per-day capacity would cost about 10 million dollars or more. The cost of crude oil is a large item in operational expense and it may run from more than one half to four fifths of the sales proceeds. The labour cost, on the other hand, seldom exceeds one tenth. The profit margin on sales is relatively small and is generally a fraction of a cent per gallon of product. Generally, operation close to capacity is essential to ensure financial success. Competition is keen; motorists, for example, are price and quality conscious when it comes to gasoline. Hence, there is great emphasis put upon improving the quality of gasolines and upon securing lower costs of producing them. Continuous attempts are also made to secure more profitable outlets for all the other products made. Refinery construction and operation are not to be undertaken lightly; careful market surveys and construction estimates are necessary; engineering skills of a high order are required for the operations; alert purchasing and selling methods are essential.

There were great annual variations in new refinery and natural gas plant investment in Alberta during the decade. The peak came in 1950 when capacity at Edmonton was being built up rapidly. All told, about $120 million was invested in the province during the 10 years in refining and natural gas facilities.

Investment in marketing facilities in Alberta rose from about half a million dollars in 1946 to about one million dollars in 1950. After 1951 new investment in marketing facilities began to rise sharply as several companies began an aggressive policy of increasing the number of their retail outlets. The major companies, such as Imperial, British American and Texaco have added many service stations in recent years, and companies like Royalite and Husky have invested heavily in such facilities. Approximately $40 million was invested in wholesale and retail marketing facilities in Alberta during the decade.

Table VI below sets out estimates of the new investment in refineries, natural gas plants and marketing facilities during 1947-56.

Table VI

New Investment in Refining, Natural Gas Plants and Facilities for Marketing Oil Products in Alberta, 1947-56

In millions of dollars

	Refineries and Natural Gas Plants	Marketing Facilities
Year 1947	2	1
1948	7	1
1949	10	1
1950	17	1
1951	13	1
1952	8	1
1953	2	3
1954	17	9
1955	22	9
1956	22	15
Total	120	42

Sources: Estimates based on data obtained from DBS and ABS.

Income Effects

The cost of materials and equipment for refinery construction may run from one third to one half of total cost, depending

upon the type and size of the plant, with two fifths as the average proportion. Large quantities of steel, tubular products and storage tanks are used. It is estimated that one ton of steel is required for each barrel-day of crude-handling capacity. In large refineries producing a full range of products, storage may be 100 or more barrels per barrel of daily capacity. Even in small refineries or those with an even flow of marketed products, storage usually exceeds 40 barrels per barrel day of capacity. These observations indicate the high ratio of materials and equipment in

Table VII

The Contribution of New Investment in Refineries, Natural Gas Plants and Marketing and of Refinery and Natural Gas Plant Operations to Personal Income in Alberta, 1947-56

In millions of dollars

Year	New Investment in Refineries and Natural Gas Plants[1]	New Investment in Marketing[2]	Operations of Refineries and Gas Plants[3]	Total
1947	2		1	3
1948	6		3	9
1949	9		3	12
1950	15		4	19
1951	12		4	16
1952	7		5	12
1953	2	1	5	8
1954	14	7	5	26
1955	18	8	6	32
1956	18	12	6	36

[1]These estimates are based on investment data in Table VI, adjusted for funds provided by Alberta residents, reduced to expenditure resulting in income for Alberta residents and multiplied by ratios declining from 2.3 to 2.0 throughout the decade.

[2]The investment for 1947-52 is deemed to have been financed almost entirely by Albertans and hence there was no income contribution. The 1953-56 estimates are based on the data in Table VI and adjusted by means of the procedure used for previous categories.

[3]Only about one fifth or less of refinery output was exported from Alberta during the decade. Hence the income contribution was small.

refineries. These materials and equipment have to be imported for refinery construction in Alberta.

The wages and salaries of construction workers average an estimated one third of the total cost of refinery construction. Local designing and engineering costs, local overhead, land costs, local taxes, profits of local contractors and the local content of materials, equipment and supplies used run to an estimated one fifth. Altogether the income accruing to Alberta from new investment in refineries and natural gas plants is an estimated one half of the total expenditure.

Investment in marketing facilities requires many imported items of equipment and materials, but a relatively high fraction of such investment accrues as income to residents because labour constitutes a large part of the cost and significant quantities of local materials are used. An estimated three fifths of the total investment accrued to residents as income.

The fractions of investment expenditure accruing to Alberta residents generated further income and the estimates of the ultimate contributions are shown in Table VII.

Refinery operations also contribute income to the region because a part of the output, averaging about one fifth during the decade, was exported from Alberta. Estimates are set out in Table VII. Since marketing operations were directed mainly toward serving the Alberta market, provincial residents furnished nearly all the funds for these by their purchases of petroleum products. Consequently little was contributed to the growth of Alberta income by these operations and no estimates were required.

The income contributions of the categories pertaining to refining and marketing increased markedly in 1947-56. They were, however, not of great importance since the activities in question were financed in high degree by Alberta residents through their purchases of petroleum products. The total contribution of the three categories was less than one-half per cent of Alberta personal income in 1947 and nearly two and a half per cent in 1956.

14

Oil Pipe Lines

By 1949 it became obvious the prairie market was altogether too small in relation to the mounting reserves and potential output of Alberta fields. Outlets for crude in other regions would be necessary and this entailed the construction of pipe lines. As early as 1948 Imperial Oil was planning a pipe line from Leduc to Regina; by 1949, after Redwater came in, plans were made for a pipe line to the Great Lakes from where oil could be transported by lake tanker to Sarnia, Ontario. This was a bold undertaking but it was necessary if the Alberta oil boom was not to be pinched off. Lacking markets outside the prairies, there would have been little incentive to continue to search for oil in Western Canada. The cost of hauling crude oil from Alberta by rail to Sarnia was greater than the price at which crude oil was delivered there from fields in the United States. Pipe line transportation offered an answer as soon as the reserves of Alberta crude became substantial.

The Economics of Pipe Line Transportation

Few industries use such highly specialized transportation as the petroleum industry. Crude oil and most of its products are liquid and can therefore be made to flow, either by pressure or gravity. This facilitates loading and unloading if the right equipment is made available. The industry has found that it pays to invest heavily in such facilities. Thus it is more economical to use special tank trucks than to pour oil into barrels which occupy valuable space and which have to be lifted on to conventional trucks. Similarly, special tank cars have been made available on the railroads and special oil tankers on the high seas. The larger the tanks of these trucks, railway cars and ships, the lower the cost of transportation of crude or products becomes. The limits upon the size of trucks and railway tank cars are apparent and soon

impose themselves. The typical oil tanker carries more than 100,000 barrels at a time and may transport from one million to six million barrels or more in a year, depending upon the lengths of trips made. The tanker provides the lowest-cost means of transport; the ultimate limitations are imposed mainly by harbour depths and docking facilities. On land, however, pipe lines carry the bulk of crude oil from well heads to refineries. It is difficult to make general statements without reference to volumes, distances and pipe diameters, but it seems that for any lengthy distance the rail transport cost per barrel is at least three or four times that of a large diameter pipe line (18 to 24 inches) operating near or at full capacity. Even pipe lines with very small diameters, for example, two to four inches, have a definite edge over tank trucks and railway tank cars, as long as throughput is fairly continuous and will go on for years. Hence, as soon as it appears that a field has ample reserves and markets, field gathering systems, employing pipe with diameters from two to eight inches, are laid.

Trunk pipe lines may be many hundreds of miles in length, and some exceed 1,000 miles. The steel pipe is usually from four to 30 inches in diameter. The pipe is laid in joints of varying lengths, depending upon the nature of the terrain. In flat country long lengths of 40 feet or so can be handled reasonably well whereas in hilly or mountainous country shorter lengths may be used. Pump stations are located along a trunk pipe line at appropriate intervals. It is very seldom that gravity alone can be depended upon to transport oil for any significantly long distance.

The first Canadian oil pipe lines were built in the Petrolia oil field in Ontario in 1875. Subsequently a number of lines, both gathering and trunk, were laid in Eastern Canada. The first oil pipe lines laid in Western Canada were those from the Turner Valley field to Calgary. There were no oil pipe lines in Western Canada before 1950 except in Alberta. Before 1950, then, Canadian pipe lines consisted of isolated small systems in Alberta and Eastern Canada. Canadian regions obtained their oil in every which way, and the railway tank car played a very important part in carrying crude oil.

Crude-oil pipe lines, then, are built to serve a single industry and usually only a few users of the oil. Large savings are effected by the movement of oil in quantity and by the fact that there is never the empty back haul so frequent in road, railway and water transport. On the other hand, the life of a pipe line depends upon the reserves of crude oil in the fields which it serves. For this reason, when a line serves a short-life field, the write-off of investment in the form of depreciation may raise tariffs unreasonably in relation to tank car or truck transportation. A pipe line operating considerably below full capacity is not usually economical; consequently, there is a tendency to err on the conservative side in

determining the diameter. Looping, the laying of additional parallel lines, is undertaken if the original line proves inadequate to handle growing traffic.

Overhead costs such as depreciation, return on the investment and taxes constitute the main part of pipe-line tariffs. The operating costs are relatively small. The larger the diameter of a pipe line, the smaller the average cost per barrel carried becomes, if the line is utilized at a level near full capacity. The outlay per barrel for pumping stations, power generation and line operation decreases as the diameter of the pipe increases. The large-diameter pipe line can even compete with water transport, especially if it shortens the distances of transport. Furthermore, pipe-line tariffs are very stable whereas tanker rates fluctuate widely.

The cost of constructing a pipe line increases by a smaller increment than does that of its capacity. For example, the cost of building a 20-inch line compared with a 10-inch line is only about two thirds greater whereas the capacity of the former is four times as great. Thus the investment cost per barrel of daily throughput of the 20-inch line is only about one third of that of the 10-inch line.

The integrated company, which has substantial interests in refineries, pipe lines and producing wells, and whose pipe lines also serve other refineries and crude oil producers, faces a complex task in deciding upon the diameter size of pipe. It is in its interest and that of crude oil producers to reach markets as economically as possible in order to keep the wellhead price at a level which encourages further exploration and drilling. At the same time, it is interested in obtaining dependable, low-cost supplies of crude oil. Both considerations dictate a policy of careful study in determining the size of pipe.

The specific gravity of the crude oil carried also affects the volume of throughput. Light crude can be pumped through a line more easily and rapidly than heavy (low API) crude. The tariff charges have to be adjusted accordingly, a factor which does nothing to alleviate the disadvantages under which heavy crudes may already labour.

Several factors, then, have to be considered in settling the question of whether or not a pipe line should be built from certain oil fields to markets. To summarize, they are the size of the supply, the size of the markets and their potentials, the minimum economic size of pipe line, alternative means of transportation and alternative supplies of crude oil and its ownership.

The Interprovincial Pipe Line

The solution of any economic problem involves a consideration of the alternatives which may be chosen as the most suitable

to meet the problem. To begin with, the oil industry in Alberta cast about for the most likely market to reach outside the prairies with a pipe line. Several areas were indicated as possibilities: Ontario, the Minneapolis and Chicago market areas, British Columbia, the Pacific Northwest states and even Montreal.

Of these the Ontario market appeared the most promising. It had a refinery capacity approaching 100,000 barrels per day and plans for refinery expansions were being made. At Sarnia, Imperial Oil had a refinery with a capacity of 55,500 barrels per day. Canadian Oil Companies had another in nearby Petrolia with a capacity of 3,700 barrels and a new one planned with a capacity of 30,000 barrels per day. In the Toronto area, British American had a 10,000-barrel refinery at Clarkson and Trinidad Leaseholds had one with a capacity of 7,000 barrels at Port Credit. Pipe lines brought Mid-Continent and Illinois crudes to Sarnia and there were tanker shipments from Trinidad into Toronto. Supplies were not always adequate and continuous. To ship Alberta crude oil to Sarnia by rail would have cost about $4.00 per barrel; this was more than the competitive price at Sarnia. It was estimated that a pipe line from Redwater to Superior, Wisconsin, could move oil to the Great Lakes at the rate of 55 cents per barrel, and lake tankers could transport oil from Superior to Sarnia for 25 cents per barrel. After allowing for terminal charges, gathering charges, line losses and so forth, the total cost would be 90 cents per barrel. With competitive crude oil supplies from Illinois and Mid-Continent priced at $3.40, the whole proposition would net Redwater producers about $2.50 per barrel. All of these estimates were, of course, subject to adjustments for changes in pipe-line construction costs and U.S.-Canadian currency fluctuations. They did indicate a realistic alternative for Alberta oil producers. While it would mean some reduction in the well-head price of oil in order to compete with Illinois and Mid-Continent crudes, this would be more than compensated by the large increase in volume.

The Minneapolis area appeared to offer another alternative. There the consumption of petroleum products was about 200,000 barrels per day, nearly all brought in from United States refineries by products pipe lines. The refinery capacity of the Minneapolis area was less than 10,000 barrels per day so there was only a very small actual market for crude oil. The Minneapolis area, then, did not provide an immediate market for Alberta crude even if the netted-back price to the producer had been favourable compared to Sarnia.

The Chicago area presented possibilities since it had a refinery capacity in excess of 300,000 barrels per day with more on the drafting boards. Crude oil was piped in from Mid-Continent and West Texas fields and the delivered price in Chicago was about $3.20 for crude equivalent in

quality to that from Redwater. By constructing a line from Superior to Chicago the total cost of delivering Alberta crude to Chicago refineries would have been about 87 cents per barrel (including U.S. import tariff), netting the Redwater producer about $2.33. Such a move would have displaced some Mid-Continent and Texas oil. The netted-back price to the Alberta producer would have been lower than in the Ontario market. It was very doubtful, too, how much Canadian crude could have been sold to the Chicago refineries.

Another prospective market was that on the west coast of Canada and the United States. The potential market in the Pacific Northwest states was about 300,000 barrels per day, but the region was almost wholly lacking in refinery capacity and petroleum products were shipped in from California. British Columbia refineries obtained their crude oil from California and since their combined capacity was below the consumption of the area, about 30,000 barrels per day, some products were also imported. The lack of refinery capacity was a serious drawback and there were several mountain ranges and much difficult terrain over which a pipe line would have to be constructed. Consequently, a western route had obvious disadvantages compared to an eastern one.

All the alternatives involved price reductions at well-head in Alberta, but it was a case of letting the industry languish in its land-locked position, or of striking out to facilitate its growth. Every well brought in as a producer meant that quotas from existing wells had to be reduced if market expansion was not achieved. By securing a large market, even though well-head prices would have to be reduced, total returns to producers would be increased materially with the great rise in the quantities of crude sold. The Sarnia market appeared to be the best alternative, and Imperial Oil decided to sponsor a pipe line to the Great Lakes.

The Interprovincial Pipe Line Company was formed early in 1949 and Imperial Oil assumed a minority interest of one third. The Canadian Parliament passed the Pipe Lines Act in April, 1949, giving the Board of Transport Commissioners jurisdiction over pipe-line routes, operations and tariffs. Shortly afterward the Interprovincial Company was chartered by a special act of parliament. The Board of Transport Commissioners approved construction of the Edmonton-Regina section in June and the section from Regina to Gretna, Manitoba, on the international border, in September. A wholly owned subsidiary of Interprovincial, the Lakehead Pipe Line Company, was formed to operate the American section from Gretna to Superior, Wisconsin.

Interprovincial raised $90 million to meet the estimated cost of the line. Twenty-year 3½ per cent bonds were issued to the amount of $72 million, 21-year four percent convertible sinking fund debentures amounting to $17 million were sold and about one million dollars was raised

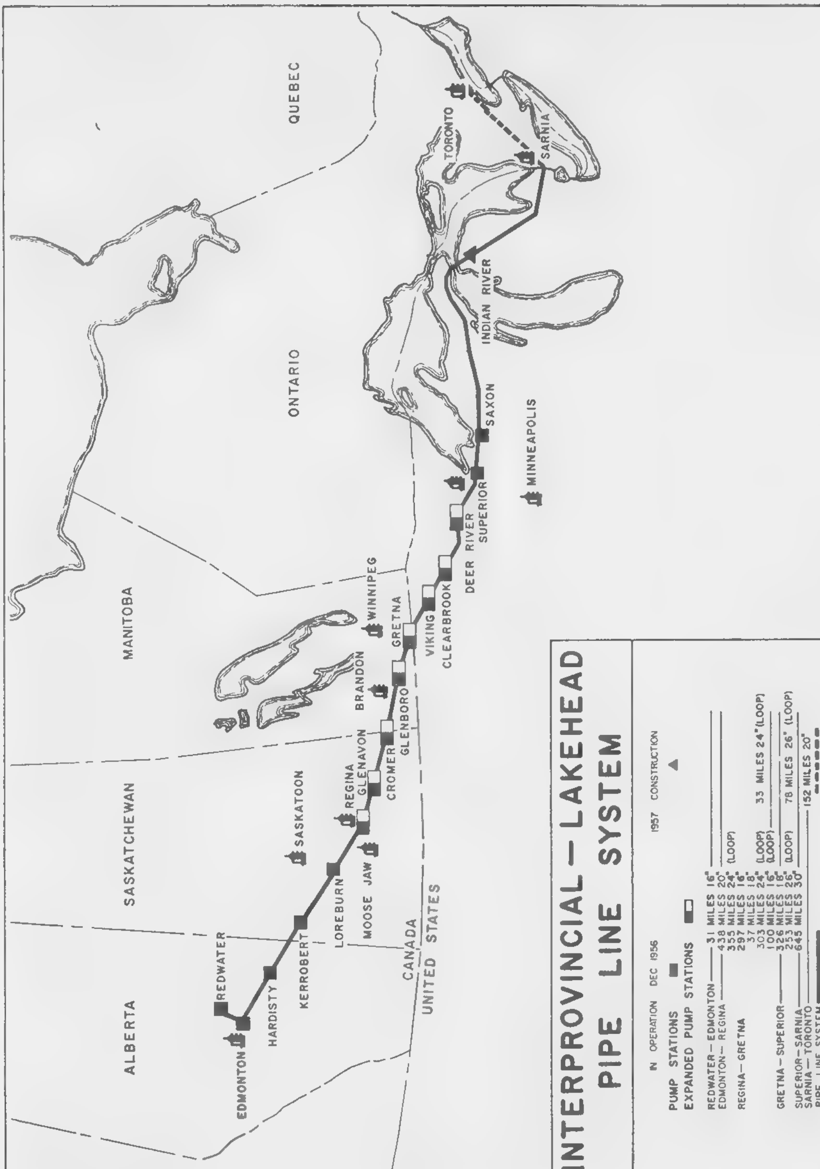


Fig. 39

by the sale of 20,014 shares of common stock at a par value of $50. Imperial Oil made an agreement with the new company to make up deficiencies in revenue if throughput fell below a certain level. Imperial also undertook to guarantee revenues up to a stipulated level. If in any year,

beginning with 1951 and ending in 1970, the quantities of oil tendered by Imperial and other oil companies to the pipe-line company for shipment should fall below an amount sufficient to provide an average daily throughput of 59,673,000 barrel-miles, Imperial promised to pay Interprovincial in cash an amount computed by multiplying the deficiency in barrel-miles by the weighted average tariff rates per barrel-mile of the company prevailing during such year. Imperial also agreed that if Interprovincial was unable to make in cash any payment required in connection with the bonds and debentures, it would purchase at par unsecured promissory notes to the amount of the deficiency. These agreements facilitated the sale of senior securities and assisted in keeping the cost of capital relatively low. The whole venture was a bold one, so much so that it is doubtful that enough capital could have been raised without the backing of Imperial.

Construction was begun in 1949 but did not proceed in earnest until early 1950 as scarce pipe became available, and the line was completed in its entirety by December, 1950. It ran from Redwater to Edmonton, southeastward to Regina, to Gretna and thence to Superior, a total distance of 1,129 miles. The initial capacity of the 20-inch, 423-mile line from Edmonton to Regina was 95,000 barrels daily, while the 334 miles of 16-inch line to Gretna and the 326 miles of 18-inch line to Superior were capable of a throughput of 70,000 barrels per day (see fig. 39). Refineries in Saskatchewan and Manitoba were supplied by feeder lines; the balance of the throughput went to Superior and thence by newly constructed tankers to Sarnia. Storage tanks with a capacity of five million barrels were completed at Superior by 1953.

The construction of a line from Superior to Sarnia was not justified during the initial stages. The Sarnia market could be reached by tankers during the open months of the year; the shipping season averaged about seven months. Storage was required at Superior to accumulate oil during the winter months. Crude oil began to be pumped into the line on October 4, 1950, for transmission to Regina. In December, oil began to flow from Regina to Superior, and on April 24, 1951, the *Imperial Leduc* docked at Sarnia, carrying the first cargo of Alberta oil to reach Ontario.

Extension of the pipe line to Sarnia was justified much sooner than anyone had anticipated. The throughput of the original line was built up rapidly. It is impossible to provide an adequate and stable flow of oil into Sarnia by tankers because the Great Lakes are not navigable during the winter season. The eastern market was found to be large enough to warrant the extension of the U.S. portion of the Interprovincial (i.e. the Lakehead Pipe Line Company) from Superior to Sarnia through U.S. territory, a distance of 643 miles. The pipe was of the extraordinarily large diameter of 30 inches, with an initial potential of 140,000 barrels

daily into Sarnia. The extension was completed in 1953, bringing the entire line to nearly 1,800 miles in length. The throughput rose from 54 million barrels (nearly 150,000 barrels daily) in 1953 to 97 million barrels (about 265,000 barrels daily) in 1956.

Looping of the western sections to increase capacity was begun in 1953 and more storage and pumping stations added. Should western Canadian oil reach the Montreal market, a great deal more looping and additional facilities would be required. In 1956 line capacity out of Edmonton was about 200,000 barrels per day and there were 15 main pumping stations between Redwater and Sarnia. Crude oil is fed into the line at Redwater, the western terminal from where it goes to Edmonton. Here additional crude oil is fed into the line from other oil fields and pumped eastward. The growing production of Saskatchewan and Manitoba fields is pumped into the line at various points. Also, crude oil is delivered at various take-off points and refineries in these provinces. Some crude is delivered to refineries in the U.S. Great Lakes region and a small amount is still being moved from Superior to Toronto by tanker.

In 1957 the company constructed a 151-mile, 20-inch extension from Sarnia to Toronto at a cost of $11 million. Some looping was also begun between Regina and Sarnia and a pumping station was added between Edmonton and Regina.

At present the Interprovincial serves nearly all the Saskatchewan refineries. The capacity of these is about 65,000 barrels per day. It serves all the Manitoba refineries with one exception (Radio Oil) with a combined capacity of about 28,000 barrels per day. Farther down the line it delivers about 15,000 barrels daily to refineries in Michigan (Bay Refining Corporation, Bay City), Minnesota (Great Northern Oil Company, St. Paul, International Refineries, Wrenshall; Northwestern Refining Company, St. Paul Park), and Wisconsin (Lake Superior Refining Company, Superior). These Great Lakes refineries have a combined capacity of more than 65,000 barrels per day, most of which constitutes a potential market which is being entered gradually. The removal of the import tariff of 10½ cents per barrel of crude oil by the U.S. government would offer Interprovincial some advantage in this great market.

Finally, the line delivered 113,000 barrels per day at the end of 1956 to Ontario refineries with a combined capacity of about 140,000 barrels per day. Of this, the largest part was taken by the Imperial Oil refinery (capacity of 78,000 barrels per day) and the Canadian Oil Companies refinery (capacity of 30,000 barrels per day) in the Sarnia area. The latter company plans to increase capacity to 50,000 barrels per day by 1961. The rest was transported by tanker to the British American refinery (capacity of 60,000 barrels per day) at Clarkson and the Regent Refining unit (capacity of 22,500 barrels per day) at Port Credit. Both of these

refineries are in the Toronto area and they are adding to their capacity by 35,000 and 85,000 barrels per day, respectively, at present. The Cities Service Company and Shell Oil are also planning to construct refineries in the Toronto area. With these projected increases in refining capacity, the pipe-line extension to Toronto becomes economic and when the line is completed, tanker movements to Toronto will largely cease. One refinery in Sarnia with a capacity of 15,000 barrels per day, the Sun Oil Company plant, continued to import its crude oil from Mid-Continent fields by pipe line until very recently.

The Trans Mountain Pipe Line

No sooner was the pipe line east to the Lakehead completed than serious consideration was given to the construction of a crude-oil line to the Pacific coast. The British Columbia market absorbed about 40,000 barrels daily in 1951 and was really too small to make it economical to construct a pipe line estimated to cost nearly $90 million. However, there was a potential market of about 250,000 barrels daily in the Pacific Northwest states. The chief drawback was that these states, Washington and Oregon, had very little refinery capacity. If only refineries could be built in Washington, it seemed entirely reasonable that Alberta crude oil could supplant a large part of the tanker shipments of refined products from California. The outbreak of the Korean War created a critical crude oil supply situation in the Pacific region. This gave impetus to proposals to pipe Alberta crude westward.

A number of Canadian and U.S. oil companies decided the risk was worth taking, and among these were some large refining and marketing companies on the U.S. Pacific coast. The group applied for a charter, and on March 21, 1951, the Trans Mountain Oil Pipe Line Company was incorporated by a special act of the Parliament of Canada. The line was to run along the CNR line from Edmonton to Jasper National Park, to cross the Yellowhead Pass and then to follow river valleys into Burnaby, a Vancouver suburb.

Construction of the 718-mile, 24-inch line was begun in February, 1952, and it was completed in September, 1953. Deliveries to Vancouver refineries began in October of the same year. At the same time plans to expand refinery capacity on the west coast were made; one of these was the construction of a 35,000-barrel-per-day refinery at Bellingham, Washington, to use Alberta crude. The final cost of the pipe line was $93 million and its initial capacity 150,000 barrels per day with a potential of 200,000 barrels if pumping stations were constructed to supplement the four set up to begin with. In 1954 a 27-mile branch line was constructed

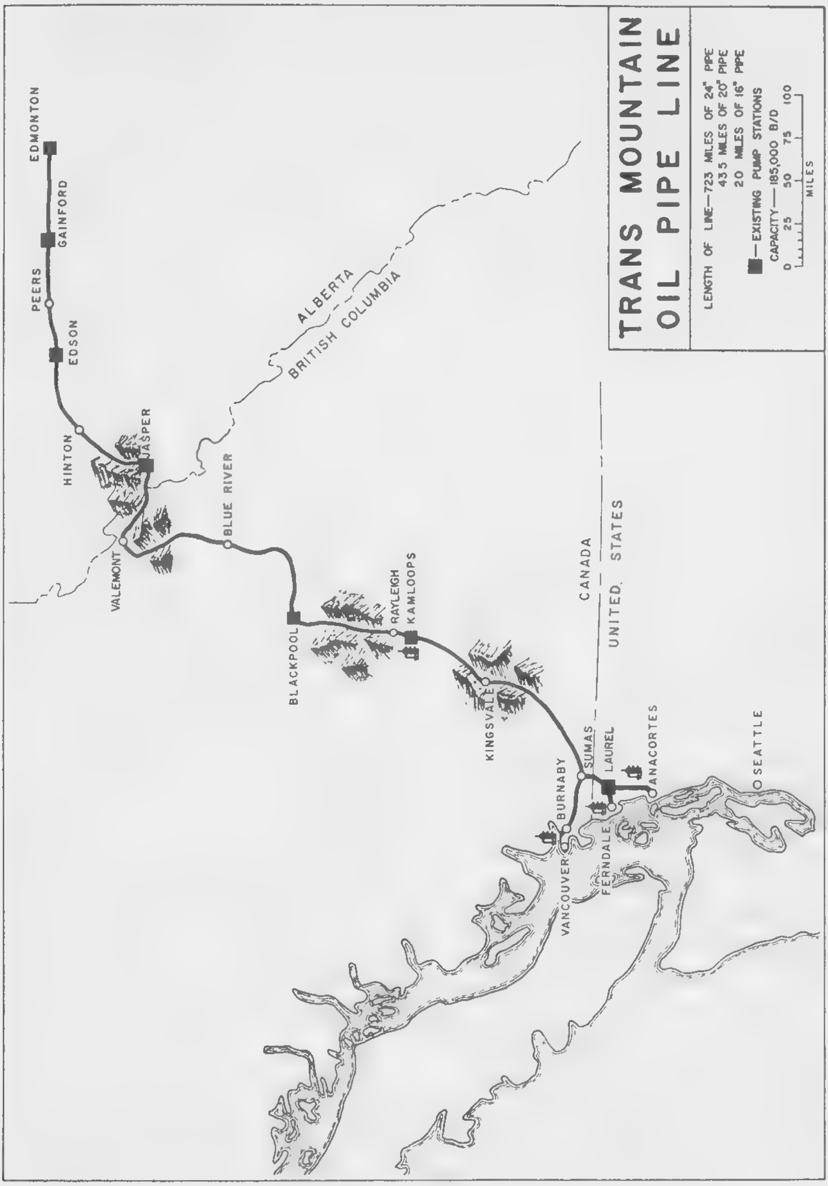


Fig. 40

to Ferndale, Washington, to serve a new refinery there; in 1955, a further 36-mile extension was made to deliver Alberta crude to another new refinery at Anacortes, Washington.

About 1,500,000 common shares were sold for nearly $15 million. Of these, 670,000 shares were taken up by six oil companies, Canadian Gulf, Imperial, Shell of Canada, Standard Oil of British Columbia (an affiliate of California Standard), Union Oil of California and Richfield Oil Corporation. Another 130,000 shares were purchased by the pipe line contractor, S. D. Bechtel. Of the rest, 250,000 shares were offered to oil-producing companies other than the main six, and the balance was sold to the general public. The six main oil companies mentioned and several small companies signed deficiency agreements with the Trans Mountain company. They guaranteed sufficient funds to service the first mortgage and collateral trust during the life of the bonds. Any deficiency payments made by the oil companies were to be repaid out of future earnings, and dividends were to be restricted while there were any deficiencies.

Two bond issues were sold in 1952; one was a 4⅛ per cent, $30-million issue and the other a four per cent, $35-million one for a total of $65 million. Another four per cent issue of $6 million was sold in 1954. In addition, bank loans were obtained to complete the financing required for the time being. As in the case of Interprovincial, more than four fifths of the funds were raised by the sale of fixed interest securities. This created a great deal of leverage which led to high earnings on the common stock once the pipe line began to operate at something near full capacity. It was estimated at the inception of the project that if only 37,000 barrels moved through the line per day to meet the demand of British Columbia refineries and a tariff of 60 cents per barrel were charged, the earnings per share would be 14 cents or not quite 1½ per cent on the investment of the stockholders. If a throughput of 200,000 barrels per day could be achieved, ultimately possible with the erection of Washington refineries, and the tariff were only 25 cents per barrel, the earnings per share would be $2.25 or about 22 per cent on the common stock investment. Both the Interprovincial and Trans Mountain lines have achieved satisfactory earnings on the common stock in recent years.

The capacity of the line was 185,000 barrels per day at the end of 1957. At the end of 1956, the line delivered Alberta crude oil to the following refineries as shown in the table opposite.

In addition, tanker shipments of crude oil to California began in January, 1956, and were running at a rate of 35,000 barrels per day at the end of the year. Small shipments were also made to Japan. Three more refineries are being planned in Washington. The Texas Company plans to complete a 40,000-barrel-per-day unit by 1959. Standard Oil of California and Richfield Oil Corporation have announced plans to construct refineries in the Puget Sound area. All these refineries will provide potential markets for Alberta crude. To meet these increases in markets,

the Trans Mountain company is installing two permanent pumping stations at Gainford and Jasper in Alberta in 1957 to replace temporary units; this is expected to boost capacity to 200,000 barrels per day. Line looping will also be undertaken which will raise capacity further to 240,000 barrels per day. It is expected that additional looping will be undertaken to reach 300,000 barrels. This is not far from ten times the average throughput of 35,000 barrels per day during the initial period of operation in 1953. For the whole year of 1956, the throughput was 47 million barrels, nearly 130,000 barrels per day, and about half the throughput of the Interprovincial.

	Crude handling capacity Barrels per day
British Columbia:	
Imperial Oil, Ioco	23,000
Royalite Oil, Kamloops	5,000
Shell Oil of Canada, Shelburn	15,500
Standard Oil of B.C.	16,000
Total British Columbia	59,500
Washington:	
General Petroleum Corporation, Ferndale	35,000
Shell Oil, Anacortes	50,000
Total Washington	85,000
Total, Pacific Coast Refineries	144,500

Other Pipe Lines

A number of crude-oil pipe lines were constructed within Alberta after the Leduc discovery. Several pipe-line companies were formed to construct and operate feeder lines to the Interprovincial and Trans Mountain systems. By the end of 1954, the Imperial Pipe Line Company had 219 miles in operation, serving the Leduc-Woodbend, Redwater and Excelsior fields. The British American Alberta Pipe Line Company laid 21 miles to deliver Redwater oil to the Interprovincial. The Canadian Gulf Pipe Line Company has a system of about 200 miles serving the Duhamel, Malmo, New Norway, Stettler, Fenn-Big Valley and West Drumheller fields. The Edmonton Pipe Line Company laid almost 100 miles of line to deliver oil from the wells in the Joarcam field. The Texaco Exploration Company built 135 miles of line to deliver

crude from the Wizard Lake, Bonnie Glen, Glen Park and Westerose field to Edmonton, primarily to the McColl-Frontenac refinery.

A major project was the Pembina Pipe Line, a 72-mile, 16-inch line from the Pembina oil field to Edmonton, undertaken in 1954 and 1955. In the latter year, the Peace River Oil Pipeline Company constructed a 106-mile line from Sturgeon Lake to the Trans Mountain line at Edson.

In 1956, Cremona Pipe Lines completed a 60-mile, eight-inch line from the Westward Ho, Sundre and Harmattan fields to Calgary refineries. The Texaco Exploration Company extended its line from the Westerose field to the Homeglen-Rimbey field; and the Rangeland Pipe Line Company, a subsidiary of Hudson's Bay Oil and Gas Company, built a 43-mile line from the Joffre field to connect with the Texaco line at Homeglen-Rimbey. The Britamoil Pipe Line in turn connected the West Drumheller field with the Rangeland line at Joffre. Finally, the Pembina Pipe Line Company completed 170 miles of line in 1956, mainly gathering lines.

Natural-gas pipe line mileage increased greatly after 1946 to serve rapidly growing urban centres, large and small. During 1956 more than 400 miles of gas pipe lines were laid in Alberta by the systems serving the Edmonton and Calgary areas and by a number of new companies. The Midwestern Industrial Gas Limited built a 34-mile line from the Alexander Indian Reserve, northwest of Edmonton, to provide gas for a new power plant of the Calgary Power Company at Wabamun and for further transmission to a new pulp mill at Hinton, 160 miles west of Edmonton. The North Canadian Oils Company completed a 136-mile line from Wabamun to Hinton during 1956. The South Alberta Pipe Lines Company laid a 55-mile line from the Etzikom gas field to furnish gas for the new chemical plant of the Northwest Nitro-Chemicals Company at Medicine Hat.

There are also some products pipe lines. In 1954 the Nisku Products Pipeline Company constructed a line from the Devon gas conservation plant to transmit natural gasoline, propane and butane to Edmonton. There are three separate lines for these products for a combined total of 66 miles. In the same year the Green River Exploration Company built two parallel lines to carry products from Pigeon Lake, southwest of Leduc, to Calmar.

The first steps taken in pipe-line construction are to survey, acquire and clear the right-of-way. Surveying and clearing are activities involving the use of much labour, most of which is hired locally. Payments to landowners accrue to the region insofar as the owners are residents. In constructing the Interprovincial line, about 2,400 landowners in Western Canada were affected. After the right-of-way is cleared, trucks loaded with pipe move along it slowly and the pipe joints are unloaded. Ditch-

ing machines dig a trench, the pipe joints are welded together and wrapped for preservative purposes, and a machine lays the pipe in the ditch. Behind come the back-fillers to refill the ditch with the dirt taken from it; on small lines this may be done by hand.

The line is then tested by closing it and pumping water or compressed air into it until the pressure exceeds the maximum it is likely to have to endure in carrying oil or gas. During the next few days the line is patrolled to detect and repair leaks. The line is also cleaned at the same time by the insertion of a "go-devil" into it. It consists of rubber and steel rollers which push forward any loose objects that somehow, despite many precautions, have got in. The go-devil is left in even after the line is carrying crude oil in order to "scrape" it and thus it allows the oil to flow unimpeded. The scrapings are removed at each pumping station. The go-devil makes a noise in its travels and if there is any major obstruction this will be very marked and can be heard easily by line patrols.

Heaters may be installed to keep the oil at a temperature at which it flows easily. Pumping stations are required for long lines and wherever gravity is insufficient to force oil through a line.

The Income Effects of Pipe Line Investment and Operation

With the construction, looping and additions to the Interprovincial and Trans Mountain lines and with the continuous provision of field gathering and interfield systems, the investment in pipe lines was relatively large in Alberta during the 1950's, with the exception of 1951. The following table sets out estimates of the new investment in pipe lines in the province in 1947-56:

In millions of dollars

1947	1	1952	17
1948	2	1953	23
1949	7	1954	18
1950	30	1955	21
1951	4	1956	21

Sources: From data obtained from ABS and DBS.

Note: Investment in natural gas transmission lines is included, but investment in gas distribution lines is excluded.

On the average an estimated 25 per cent of the cost of constructing the pipe lines consisted of wages, salaries, regional contractors' margins

and consulting fees. Regional taxes, payments for rights of way, and purchases of regional materials and power made up an estimated 15 per cent of the total cost. Included in this are the receipts of owners and employees of businesses handling imported machinery, equipment and supplies as salesmen, servicemen, jobbers and transport workers. On the basis of these estimates, about 40 per cent of the investment in pipe lines accrued to Alberta residents while the rest, consisting of pipe, pumps, machinery and equipment, was spent "abroad".

Table VIII

Estimated Income Contributed by New Investment in Pipe Lines and Petroleum Transportation Operations in Alberta, 1947-56

In millions of dollars

	From Investment[1]	From Operations[2]	Total
1947	2	1	3
1948	3	2	5
1949	7	2	9
1950	23	6	29
1951	3	10	13
1952	12	13	25
1953	16	15	31
1954	13	16	29
1955	14	16	30
1956	14	16	30

[1]Estimated from investment data, adjusted for non-resident funds, regional content of expenditures and generative ratio.

[2]Estimated from data of ABS pertaining to salaries, wages and other regional items and adjusted for non-resident funds and generative ratio.

Pipe wrapping is now manufactured by the Peace River Glass Company at Fort Saskatchewan and pipe for field gathering systems began to be manufactured in 1956 by the Alberta Phoenix Tube and Pipe Company. Before 1956, however, they had no influence upon the regional supply.

Estimates of the income generated in Alberta by pipe line construction are set out in Table VIII. Regional income contributed by pipe line operations are also shown. An operating staff is required to feed and measure the oil or gas put into a line, to regulate the pressures and to

patrol the line. Items of expenditure on operation which create regional income are wages and salaries, fuel and electricity, certain materials and supplies, regional taxes and leases and rentals. In making the estimates in Table VIII an allowance has been made for railway and trucking operations applicable to the transportation of crude oil and also for storage operations. On the other hand, the expenditures on the operation of gas pipe lines and gas utilities have been excluded because they were financed almost entirely by Alberta residents by their purchases of natural gas.

Only a relatively small proportion of the expenditures on new investment in and operations of pipe lines in Western Canada was made in Alberta. Furthermore, a high ratio of expenditure on new investment in pipe lines within the province was spent on imports. Hence the direct effects upon the growth of income in Alberta were relatively small. In 1947 the contribution was less than half of one per cent of the provincial personal income; in 1956 it was about two per cent. However, the construction of the two great pipe lines was of major importance. Without them, the oil development in the province would have been stunted and arrested. With them, continuous investment in the development of the petroleum resources of the province was stimulated and investment in other regional ventures induced.

15.

Markets for Alberta Crude

In 1946 most of the crude oil produced in Alberta was marketed within the province. Out of an output of seven million barrels, only one million barrels were exported, chiefly to Saskatchewan refineries. With falling output in the Turner Valley it appeared that Alberta would soon, like Saskatchewan, become an importer of oil. The new discoveries changed this and also solved the crude supply problem of the whole prairie region. Eventually Alberta crude oil went to Ontario and to the Pacific coast. But before we turn to these developments, let us look at the crude-oil supply and demand conditions on the prairies in 1947.

Supply and Demand Conditions in 1947

The conditions governing the prices of crude oil and products in the prairie provinces were unusual just before the Leduc discovery. The demand for products was rising rapidly while prices continued to be subject to control by the federal Wartime Prices and Trade Board. The supply of crude oil came mainly from the Turner Valley field and from the United States. The price of crude oil at Turner Valley, the main domestic source of supply, was controlled by the federal board mentioned. This price was considerably below that of imported crude oil from the United States. Prairie refineries were paid subsidies by the federal government on their imports of crude oil. These subsidies were scaled to the cost of transporting U.S. crude oil to individual refineries, and in some instances they exceeded one dollar per barrel.

The price of crude oil imported from the U.S. had risen gradually during the war years and by the end of the war it was at a level far above

the price paid to the domestic producer, a situation which did nothing to keep the latter happy. What the price of domestic crude would have been without controls and without import subsidies nobody knows, but it would have been higher than the actual level. The prices of gasoline and other products would accordingly have been higher also.

As early as January 1, 1946, the federal government reduced subsidies by 45 cents per barrel, raised Turner Valley crude oil prices by the same amount and permitted an increase in gasoline prices of two cents per gallon. On January 12, 1947, the federal government ceased paying crude oil import subsidies altogether and permitted an increase of 50 cents per barrel in the posted price of Turner Valley crude oil. At the same time the government announced that after April 1 it would no longer levy its wartime tax of three cents per gallon on refined products. In March the government announced that it would remove all price controls on gasoline and tractor distillates on April 1, 1947. Since the provincial governments imposed additional taxes on refined products after April 1, the prices of such products rose during 1947. At the same time, the price of crude oil continued to increase in the United States, and so did freight rates.

A discrepancy between the cost of imported and domestic crude continued to persist during 1947. The posted price of crude oil at Turner Valley was raised substantially three times—in April, in October and in December (see Table IX)—to bring it more and more in line with the price paid by prairie refineries for imported crude oil. Such increases would have continued throughout 1948 if the Leduc-Woodbend discovery had not been made.

Subsequent Developments

Production from the Leduc-Woodbend field was great enough in 1947 to make itself felt in terms of price changes. In 1948, however, output from the field was substantial enough to permit exports from the province of nearly three million barrels to Saskatchewan and Manitoba refineries. To make Alberta crude increasingly competitive with imported crude from the United States, posted well-head prices were reduced markedly on December 1, 1948 (see Table IX). In 1949 the Canadian dollar was devalued. This increased the competitive advantage of Alberta crude oil in the prairies very greatly. At the same time, it increased the cost of materials and equipment imported by the petroleum industry for use in surveys, drilling, producing and refining. The well-head prices of crude oil in Alberta fields were raised on September 24, 1949, and the new prices were still low enough to exclude substantial imports of U.S. crude into the prairie region.

Table IX

Posted Crude Oil Prices in Selected Alberta Fields, 1947-57

Dollars per barrel

	Turner Valley 41° API	Leduc-Woodbend 39°-40° API	Redwater 34° API
January 15, 1947	2.63[1]		
April 1, 1947	2.98		
July 8, 1947	2.98	2.675[2]	
October 28, 1947	3.18	2.95[3]	
December 12, 1947	3.68	3.47	
December 1, 1948[4]	3.25	2.95	2.68[5]
February 1, 1949[6]	3.40	2.95	2.68
September 24, 1949[7]	3.60	3.20	2.88
October 16, 1950	3.45	3.05	2.73
April 24, 1951	3.10	2.61	2.44
June 1, 1951	3.10	2.62	2.46
April 23, 1952	2.955	2.475	2.315
October 15, 1952	2.955	2.425	2.325
March 19, 1953			2.385
July 21, 1953	3.275	2.745	2.645
July 1, 1954	3.275	2.755	2.645
October 15, 1954	2.895	2.665	2.555
January 7, 1955	2.665	2.595	2.485
February 1, 1955	2.665	2.60	2.49
January 16, 1957	2.665	2.78	2.67

Source: PNGCB for 1947-1955 and *Oil in Canada* (change of January 16, 1957).

[1]Raised by 50 cents per barrel over previous posted price.

[2]This was the first posted price. Early deliveries were sold at $2.33 per barrel.

[3]A resultant of a general increase of 20 cents per barrel, plus a 7½ cents saving in transportation when the pipe line to Nisku opened on October 28, 1947.

[4]On December 4, 1948, the British American Company posted prices 15 cents higher in Turner Valley and 10 cents higher in Leduc-Woodbend and Redwater.

[5]The first crude oil sold in Redwater was priced at $3.20 for 34° API gravity.

[6]The price was raised by 15 cents by Royalite and Imperial in Turner Valley on February 1, 1949, to bring their posted price in line with that of British American. Two prices still prevailed in Leduc and Redwater.

[7]Imperial, Royalite and British American raised their posted prices by 20 cents per barrel in the Turner Valley field. In the Leduc-Woodbend field, Imperial raised its posted price by 25 cents and British American by 15 cents, bringing about equality in the prices posted by both companies. In Redwater, Imperial raised its price by 20 cents and British American by 10 cents to bring about price equality.

Exports of Alberta crude oil to Saskatchewan and Manitoba refineries rose to eight million barrels in 1949 and to 11 million barrels in 1950. In a little more than two years after Leduc, Alberta oil supplied both Alberta and Saskatchewan. Much of Manitoba, including Winnipeg, could not be reached with the prevailing well-head price of crude. Furthermore, the refinery capacity of that province was small.

The completion of the Interprovincial Pipe Line, however, changed matters greatly. The pipe line reduced crude oil transport charges from Edmonton to Regina from a railway rate of $1.37 per barrel to a pipe line tariff of 29 cents. The tariff from Edmonton to Superior was only 54 cents compared with a railway rate of $2.43 per barrel. From Edmonton to Sarnia by pipe line and tanker the transport charge was 80 cents per barrel, somewhat lower than the original estimate (see Chapter 14).

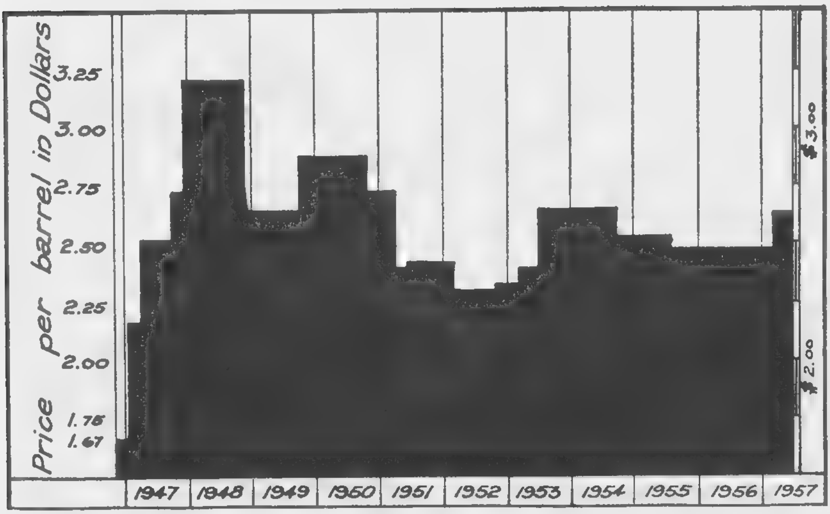


Fig. 41 Prices of 34° API Redwater crude, December 1946 to mid-1957
Note: Data for 1947 and most of 1948 are based on prices for equivalent crude if Redwater had been in production

There was a fundamental change in the geographic pattern influencing well-head prices in Alberta. With the completion of the Interprovincial Pipe Line, the price of crude oil in Alberta and the prices of petroleum products on the prairies came to depend upon the cost of crude oil at Sarnia, Ontario. In essence, the well-head price of light crude oil in Alberta was determined largely by the well-head price of Mid-Continent

crude oil plus pipe-line tariffs to Sarnia, less the pipe-line tariff from Edmonton to Superior and the tanker rate from Superior to Sarnia. When the Interprovincial was completed to Sarnia, the well-head price of light Alberta crude was adjusted to a level equal to the price at Sarnia less the pipe-line tariff to that point.

The years immediately following 1946, then, were ones of continuous flux of crude oil supplies and prices. Disequilibrium of a major order was evident in 1946-47 as the regional supply diminished, as regional producers received prices lower than those paid for imported crudes, and the regional demand increased. The removal of price controls and subsidies in 1947 was followed by several upward adjustments in the prices of crude oil produced in the region. With the discoveries of Leduc and Redwater, the regional supply was augmented and crude-oil prices fell. With the construction of the Interprovincial Pipe Line, Alberta crude began to move out of the prairie region and its price came to depend mainly upon pipe-line and tanker tariffs and upon the price of crude oil at Sarnia, Ontario, the export market in which Alberta crude met the competition of other crudes.

The well-head prices of crude oil in Alberta fields were reduced in late 1950 and again in April, 1951, when the first Alberta crude arrived in Sarnia. There were further downward adjustments in prices during 1952. There were increases during 1953, followed by declines during 1954 and 1955. These price changes resulted essentially from forces affecting the price of crude oil at the Sarnia refineries. Table IX sets out the details and fig. 41 portrays them graphically.

With the rising cost of finding oil in North America and with the Suez crisis, price increases became imminent in 1956. In January, 1957, the well-head prices of crude oil in the United States were increased by as much as 35 cents per barrel in Gulf Coast fields and by as much as 25 cents per barrel in Illinois, Mid-Continent and Rocky Mountain fields. Canadian prices followed upward but by smaller increments than in the United States, thus allowing for the rise in the premium on the Canadian dollar which had made U.S. crude increasingly competitive. The prices of Leduc-Woodbend and Redwater crude were raised by 18 cents per barrel and the Pembina price by 13 cents. Price changes are not undertaken lightly by the petroleum industry. In this instance, the general upward price change brought an opportunity to both the American and Canadian branches of the industry to bring prices in all fields into line with each other.

By and large, the discovery of oil in Alberta, followed by the construction of a pipe line to Sarnia, reduced the price of crude oil in the prairie region. Lacking this and lacking economic synthetic or other alternatives mentioned in Chapter 6, the prairies would have been de-

pendent upon imported crude oil if hauled in by rail from the United States. Prices may have been in the neighbourhood of five dollars per barrel, a level considerably higher than present prices which are below three dollars per barrel for light-gravity crude at practically all refineries on the prairies.

Changes in the Prices of Petroleum Products

A widespread economic benefit that the Alberta oil discoveries brought to the prairie region were the reduction in the prices of petroleum products. In fig. 42 the tank-wagon prices of "regular" gasoline are plotted for four cities: Edmonton, Regina, Winnipeg and Montreal.

In 1946 Montreal had the lowest price of the four cities and Edmonton and Winnipeg the highest. The prices in all the cities rose sharply in 1946-48. Prices fell in both Edmonton and Regina in 1949 as Leduc and Redwater crude came to serve these centres in large volume, and the Edmonton price became the lowest of the four. In 1950 prices rose in all but Edmonton. In 1951 the lower transportation costs effected by the Interprovincial Pipe Line and the reduction in well-head prices of crude in Alberta brought about marked price decreases in Winnipeg and Regina and smaller ones in Edmonton where there was only the reduction in well-head prices. The situation in 1956 as against 1946 is summarized in the following table:

Tank-Wagon Price of Esso Gasoline

Cents per gallon

	1946	1956	Change
Montreal	16.5	22.3	5.8
Winnipeg	20.0	22.4	2.4
Regina	19.0	21.7	2.7
Edmonton	19.9	20.4	0.5
Calgary	17.0	21.4	4.4

The price increases on the prairies were small for such an inflationary period as 1946-56, and in Edmonton there was almost no increase in the tank-wagon price of gasoline. Without the major discoveries of the period, the tank-wagon prices in Edmonton and Calgary would probably have been in the neighbourhood of 30 cents per gallon instead of a little more than 20 cents. After adding provincial gasoline taxes and retailers' margins, the price of regular gasoline might have been between

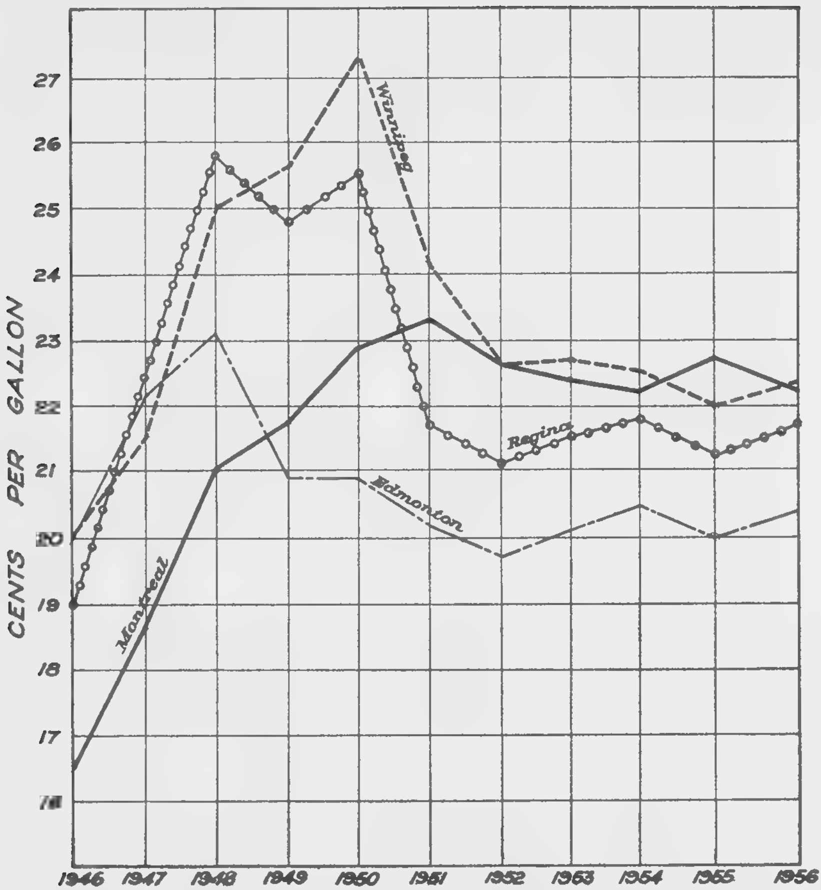


Fig. 42 The tank-wagon prices of regular gasoline in selected cities, 1946-56
Note: Tank-wagon prices are those paid by retailers. The retail price includes the retailer's margin and provincial taxes

50 and 60 cents per gallon in the two cities instead of the present 40 cents or less. This statement is predicated upon the lack of alternative supplies from sources more economic than the import of crude oil by rail from the United States.

On this basis, the price reductions released millions of dollars of the disposable income of prairie consumers for spending on other goods and services or for savings. As early as 1949 the total involved came to an estimated $12 per person in the prairie provinces. Currently it runs at an estimated $25 per person. Furthermore, the reductions have assisted in

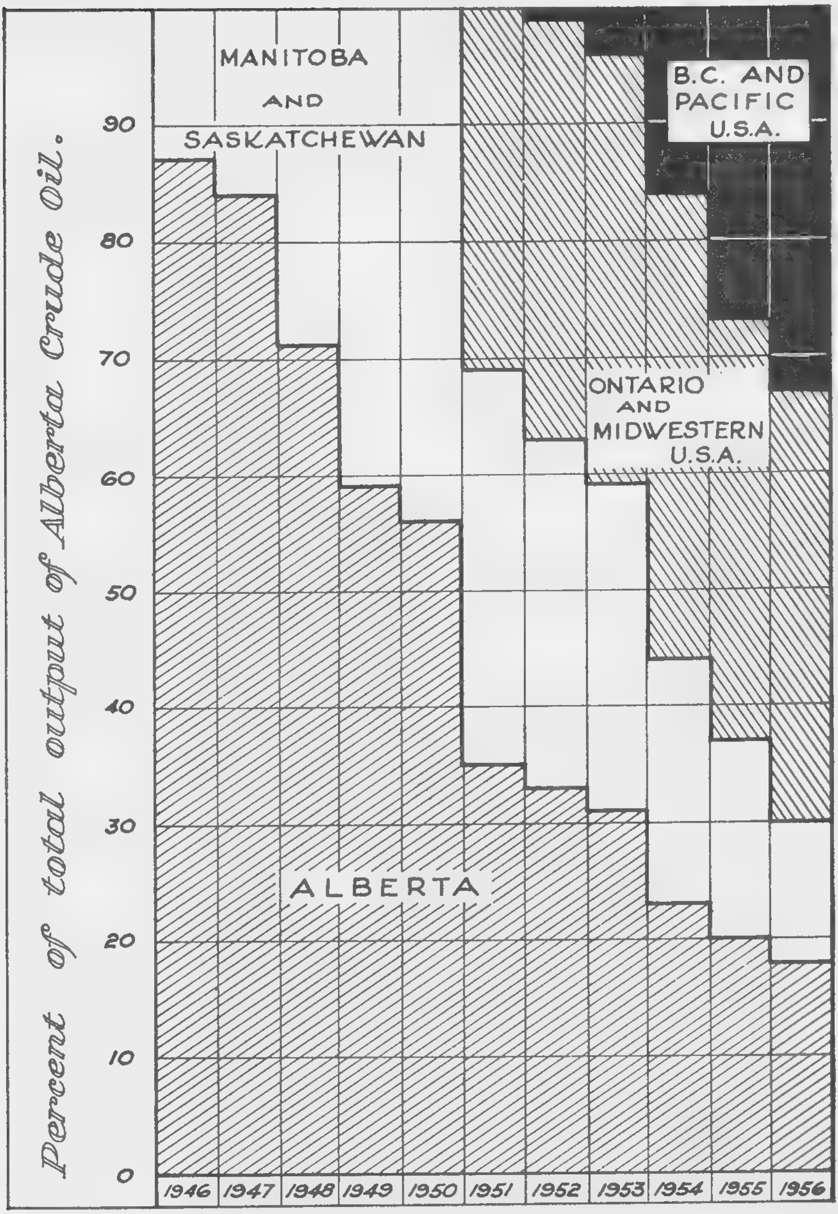


Fig. 43 The percentage of Alberta crude-oil output sold in main market areas, 1946-56   Source: PNGCB

lowering the operating costs of prairie farms and businesses; they have tended to stimulate investment in machinery and equipment by agriculture and other industries.

Table X

Sources and Disposition of Crude Oil in Alberta, 1946-56

In millions of barrels

	1946	1947	1948	1949	1950	1951	1952	1953	1954	1955	1956
Sources											
Production from Alberta fields[1]	7.1	6.8	10.5	19.8	27.1	45.9	58.9	76.8	87.6	113.9	143.9
Imports of Saskatchewan crude[2]						0.8	1.3	1.5	1.8	1.8	1.7
Total Sources	7.1	6.8	10.5	19.8	27.1	46.7	60.2	78.4	89.4	114.9	145.6
Disposition											
Inventory changes			0.1	0.4	2.4	0.8	0.8	8.7	–0.2	2.6	0.3
Alberta[3]	6.2	5.7	7.4	11.4	13.8	16.1	19.8	21.4	20.6	23.0	25.4
Saskatchewan[4]	1.0	1.1	2.4	6.8	9.4	11.1	11.9	14.4	13.7	12.8	12.9
Manitoba[4]			0.7	1.2	1.6	4.6	6.1	5.5	5.2	6.1	4.8
Ontario						13.7	20.0	23.4	34.1	36.3	43.7
British Columbia							0.5	2.7	13.5	19.3	21.9
U.S.A.—Great Lakes						0.5	1.1	2.2	1.7	3.3	11.1
U.S.A.—Puget Sound									0.9	11.4	19.2
Vancouver Marine											6.2
Total Disposition	7.1	6.8	10.5	19.8	27.1	46.7	60.2	78.4	89.4	114.9	145.6

Source: PNGCB.

[1]Includes 0.4 million barrels of natural gasoline for each of the years 1946 and 1947.

[2]Imports by the Lloydminster refineries from the other heavy crude fields.

[3]Alberta refinery runs plus some miscellaneous uses.

[4]Combined for 1946 and 1947.

The Disposition of Alberta Crude Oil

During 1946-50 all the Alberta crude oil produced was marketed on the prairies. After 1950 oil began to flow to the Great Lakes area of the United States and to Ontario. This market absorbed 14 million barrels in 1951 and 55 million barrels in 1956, a fourfold increase in five years. There was a particularly marked increase in the purchases by United States refineries in the Great Lakes area (including Minnesota) during 1956.

Alberta crude began to move to British Columbia in 1952, when a total of half a million barrels was marketed there. In 1956 the refineries in the coast province purchased almost 22 million barrels. With the completion of two refineries in the Puget Sound area of Washington, exports to the Pacific Northwest of the United States began in 1954; they increased rapidly from less than one million barrels in that year to more than 19 million barrels in 1956. With the shortage of tankers during 1956 it became economic for some California refineries to import Alberta crude by tanker from Vancouver. Such shipments exceeded six million barrels in 1956.

Table X sets out the sources and disposition of crude oil in Alberta in detail for the period 1946-56. Figure 43 shows the disposition graphically. Figure 44 shows it by way of a map for the year 1956.

During the decade Alberta crude oil was marketed increasingly outside Alberta. Figure 44 shows this strikingly. The proportion of Alberta crude oil output which was exported to other parts of Canada and to the United States ran from 13 per cent to 82 per cent in 1946-56. It is plain that Alberta developed a new large export industry during the decade.

The first market for the growing output of Alberta crude oil after the Leduc discovery consisted of the other prairie provinces. They purchased a growing proportion until 1951; since that date they have taken a falling fraction as they became oil producers in their own right. This trend will continue with the prospective increases in their crude oil output. Even now Saskatchewan is an exporting province and Manitoba produces much of its requirements. The following table of crude oil production in Western Canada is illustrative of this development:

In millions of barrels

	Alberta	Saskat-chewan	Manitoba	Total Prairies
1952	58.9	1.7	0.1	60.7
1953	76.8	2.8	0.7	80.3
1954	87.7	5.4	2.1	95.3
1955	113.0	11.3	4.1	128.5
1956	143.9	21.1	5.8	170.8

Source: CPA.

The indicated output of Saskatchewan for 1957 is about 35 million barrels. Currently the southeastern portion of the province is undergoing intensive exploration and development and the rate at which oil is being found is very high. Except for certain quantities of special light crudes,

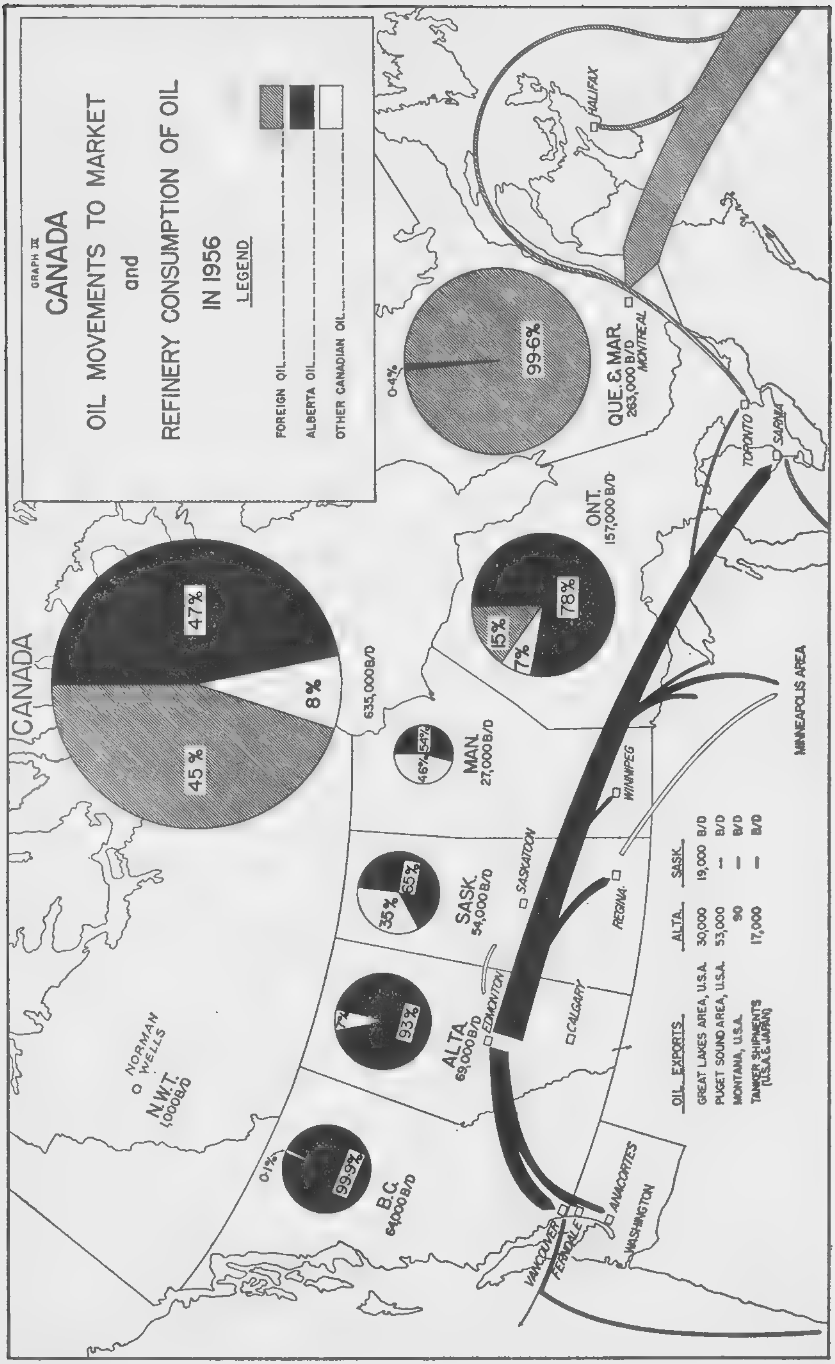

GRAPH III
CANADA
OIL MOVEMENTS TO MARKET
and
REFINERY CONSUMPTION OF OIL
IN 1956
LEGEND
FOREIGN OIL
ALBERTA OIL
OTHER CANADIAN OIL
CANADA
635,000 B/D
47%
45%
8%
QUE. & MAR.
263,000 B/D
99·6%
0·4%
ONT.
157,000 B/D
78%
15%
7%
MAN.
27,000 B/D
54%
46%
SASK.
54,000 B/D
65%
35%
ALTA.
69,000 B/D
93%
B.C.
64,000 B/D
99·9%
0·1%
N.W.T.
1,000 B/D
NORMAN WELLS
HALIFAX
MONTREAL
TORONTO
SARNIA
WINNIPEG
REGINA
SASKATOON
EDMONTON
CALGARY
VANCOUVER
FERNDALE
ANACORTES
WASHINGTON
MINNEAPOLIS AREA
OIL EXPORTS
ALTA.
SASK.
GREAT LAKES AREA, U.S.A. 30,000 19,000 B/D
PUGET SOUND AREA, U.S.A. 53,000 — B/D
MONTANA, U.S.A. 90 — B/D
TANKER SHIPMENTS (U.S.A. & JAPAN) 17,000 — B/D

Fig. 44

the market for Alberta crude in the other prairie provinces cannot be expected to expand. This implies that Alberta has become highly dependent upon markets for crude oil outside the prairie region. Saskatchewan also is becoming dependent upon such outside markets. In recent years it has exported considerable quantities of medium-gravity crudes to the Minneapolis-St. Paul area.

The second market reached by Alberta crude, Ontario, absorbed nearly one third of Alberta's oil in 1951. Together with the U.S. Middle West, it absorbed two fifths of Alberta's crude oil output in 1954; the proportion fell slightly with the opening of the Pacific coast market. Ontario has taken very much the largest share of the total oil shipped eastward. There are prospects of increasing sales in Ontario because refinery capacity in the province is undergoing rapid expansion.

Refinery capacity is also expanding markedly in Minnesota, Wisconsin and Michigan along or in the vicinity of the Interprovincial route. There is also the great potential of the Detroit market. A growth in the sales of Alberta crude oil in these markets can be looked for provided the United States does not raise barriers against Canadian oil. The removal of the U.S. import duty of 10½ cents per barrel would make this market very promising.

A question of the day is the possibility of extending the Interprovincial Pipe Line to Montreal. Such a move would make it feasible to sell Alberta and Saskatchewan crude in this great market, but this would require reductions in the prices of crude at the well-head. It might also require reductions in pipe line tariffs. The volume of additional sales would have to more than offset price decreases to make market expansion worthwhile. The refinery capacity of companies with crude oil production in Western Canada is substantial in the Montreal area. Refinery capacity is being expanded more rapidly in Ontario than in the Montreal area, thus reducing the relative importance of Montreal refinery capacity.

The Pacific coast region has become an important outlet for Alberta crude, rising from one per cent of the Alberta output in 1952 to one third in 1956. Here very much the largest portion is bought by the refineries in the Puget Sound area. This market is promising. The economic progress of the Pacific region is rapid, inducing large annual increases in petroleum consumption. A great increase in refinery capacity in the Puget Sound area is contemplated by 1960.

Until recently the competitive position of Alberta crude oil had been favourable in the Vancouver and Puget Sound areas. The laid-down price of crude at the Vancouver refineries equals the price at Edmonton plus the Trans Mountain pipe-line tariff of 45 cents per barrel. In addition, there are some handling charges and allowances for line losses, making

the Vancouver price about 50 cents higher than that at Edmonton. Another 20 cents per barrel is added to arrive at the price at the Puget Sound refineries. This covers a U.S. import duty of 10½ cents per barrel, transport costs from the Vancouver area and the exchange differences between the Canadian and American dollar. The prices of Alberta crude at Vancouver and the Puget Sound refineries have been sufficiently low to exclude nearly all competitors. Shipments of Alberta crude to California refineries largely ceased in 1957 as the Suez Canal was reopened and tanker space became increasingly available. With the great planned increase in tanker construction and a continuous flow of oil from the Middle East, the entry of Alberta crude oil in the California market is not an immediate prospect. Alberta crude oil sales have also declined in the Puget Sound area, as the United States government has recently imposed restrictions on imports.

During 1957 the United States government requested various oil companies in that country to reduce their imports of crude oil. The effect has been to restrict growth of the market for Alberta crude in 1957 and 1958. The pressure on the United States government to curtail crude oil imports comes mainly from many small independent producers of crude oil in that country. This pressure cannot be effective indefinitely as an increasing number of wells in the United States become "strippers", as the demand for oil rises over the long run and as the costs of finding and producing oil in the United States continue to rise. Authoritative studies such as those made by the Chase Manhattan Bank indicate that the present policy of the United States government will have to change in time. In the meantime, the short-run market prospects for Alberta crude in the United States are not bright, but the long-term prospects must still be regarded as good.

The Income Contribution of Crude Oil Production

As crude oil exports from Alberta increased, so did the personal income of the region. Two kinds of disbursements create income for Alberta residents when crude oil is produced. One is the expenditure on labour and materials to lift and store the oil; the other is the distribution of royalties to holders of mineral rights.

Producing costs (lifting and storage at well-head) in Alberta averaged about 50 cents per barrel in 1947. The average rose for a variety of reasons to almost 60 cents per barrel in 1950. With the large outputs of shallow fields like Redwater and Joarcam, the average fell to about

35 cents in 1953. After that date, the outputs of fields with relatively great depths, for example, Pembina, became important and the average is currently in the neighbourhood of 50 cents per barrel. There were, of course, many variations among fields and over periods of time.

About 35 per cent of the total cost of producing consists of wages and salaries. Another 20 per cent or so may be classified as income accruing to Alberta residents, traceable to the use of fuel, electricity, materials and supplies purchased in Alberta. All told, then, an estimated 55 per cent of the producing expenditures create regional income and currently a little more than 25 cents per barrel accrues to Albertans directly as income. After multiplying by two, the ultimate income generated is about 50 cents per barrel.

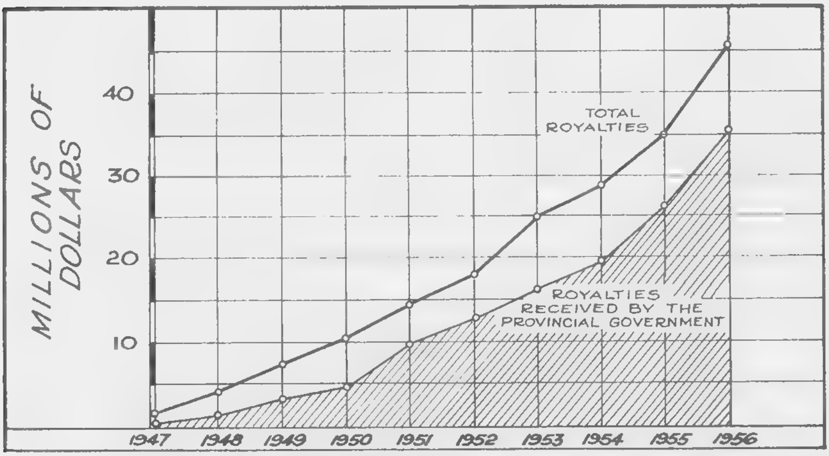


Fig. 45 Royalties from crude oil and natural gas production in Alberta, 1947-56 Sources: Royalties received by the provincial government were the actual as reported by the Government of Alberta, Dept. of Mines and Minerals. Total royalties were estimated by the writer from data on the value of production

The major recipient of royalties during the decade was the provincial government whose share was close to four fifths of total royalties distributed in 1956. The share was considerably lower during the early years of the decade before Redwater, Pembina and other fields with little freehold acreage became important producers. An estimated one tenth

of the royalties distributed in 1956 went to individual residents of Alberta and the balance was paid to corporations. Currently, then, nearly nine tenths of the royalties distributed are received by Alberta residents and the provincial government. Fig. 45 portrays the situation graphically for the decade.

What income accrued to Alberta residents from producing expenditures and the distribution of royalties? The estimates, based on proportions suggested in previous paragraphs, are set out in Table XI.

Table XI

The Income Contributions of Producing Expenditures and Royalty Distributions in Alberta, 1947-56

In millions of dollars

	From Producing Expenditures[1]	From Royalties[2]	Total
1947	2	2	4
1948	8	4	12
1949	10	7	17
1950	13	10	23
1951	18	16	34
1952	22	21	43
1953	22	27	49
1954	30	32	62
1955	43	44	87
1956	58	58	116

Sources: Data were obtained from ABS surveys and industry sources.

[1]Includes estimates of natural gas producing expenditures. The estimated expenditures were reduced to allow for import content and provision of funds by Alberta residents and the result multiplied by the generative ratio.

[2]The government royalty receipts were reduced by the estimated extent to which the provincial government had surpluses (i.e did not spend receipts), by the import content of government expenditures and by the extent to which Alberta residents contributed funds. The result was multiplied by the usual generative ratio. Royalty receipts of persons were reduced by the extent to which Alberta residents furnished funds for crude oil production by their purchases of petroleum products and the result was multiplied by the usual ratio.

In 1947 expenditures on producing operations and royalty distributions generated less than one per cent of the personal income of the province. In 1956, they furnished more than seven per cent, a substantial contribution, providing a livelihood for at least one person out of fifteen in Alberta in one way or another. The income generated is dependent upon the exports of crude oil. Generally speaking, each barrel of oil exported from the province generates about one dollar of income for Alberta residents.

16

Land Acquisition

In nearly all countries except the United States, governments own most of the oil and natural gas rights. Canada is no exception. It has been estimated that the provincial government of Alberta owns the oil and natural gas rights on 93 per cent of the area of the province. The situation is similar in British Columbia. In Saskatchewan, and even more so in Manitoba, the percentage owned privately is considerably greater than in the two most westerly provinces because their sedimentary areas were settled earlier and mineral rights were alienated from the Crown at the time of settlement. Oil companies operating in Western Canada, then, deal mainly with the provincial governments and with the federal government as far as the Northwest Territories are concerned.

The History of Western Canadian Oil and Natural Gas Rights

In Western Canada both surface and subsurface rights were originally inseparable. The Hudson's Bay Company held title to both under its royal land grant of 1670. The Dominion of Canada purchased the lands held by the company and the transfer was made in 1870. The Dominion also acquired surface and subsurface rights in all other territory north of the 49th parallel from the British Crown. The Hudson's Bay Company retained rights to both in certain areas such as around their trading posts and in specific sections of townships in the surveyed area of Western Canada. Beginning in the 1880's, the Dominion made grants of land, including both surface and subsurface rights, to the Canadian Pacific Railway Company and other railroad companies. Before 1887 the Dominion also issued patents, which included both kinds of rights, to homesteaders and purchasers of land. Thereafter, homesteaders and purchasers obtained patents which included surface rights

only. Much of Manitoba was settled before 1887, and consequently there is a high proportion of freehold mineral rights or acreage in that province.

In Saskatchewan, settlement came later than in Manitoba, but the main area homesteaded before 1887 was in the southwest which is now an important oil-producing district. About half of the sedimentary area is estimated to be freehold. Alberta and the Peace River Block in British Columbia were settled last of all with the result, already noted, that less than one tenth is freehold.

In 1930 the prairie provinces obtained the Crown lands within their borders from the federal government. The latter still has small land rights in the three prairie provinces and nearly all the rights in the Northwest Territories. It also administers the rights on Indian lands. Table XII indicates the ownership of petroleum and natural gas holdings of oil companies and operators at the end of 1956.

It should be kept in mind that the acreage data in Table XII include only lands which have actually been leased or reserved by oil companies and operators. The acreage so leased in Alberta in 1956 was about 60 per cent of the land area of the province and about two thirds of the

Table XII

Estimated Petroleum and Natural Gas Acreage Holdings of Lessees Classified by Type of Lessor, December, 1956, Western Canada

Percentage of total acreage leased or reserved

	B.C.	ALTA.	SASK.	MAN.	N.W.T.	TOTAL
Provincial Government	99.8	84.8	58.4	22.3	0.0	70.7
Federal Government	0.0		0.1	0.2	100.0	9.3
Indian lands		0.9	0.2	0.2	0.0	0.3
Total Crown	99.8	85.7	58.7	22.7	100.0	80.3
Canadian Pacific Railway	0.0	7.8	3.5	2.2	0.0	4.8
Canadian National Railway	0.0		6.7	4.1	0.0	1.7
Hudson's Bay Company		1.6	5.1	8.9	0.0	2.3
Individual freehold	0.1	4.1	23.9	61.1		10.0
Other		0.8	2.1	1.0	0.0	0.9
Total freehold	0.2	14.3	41.3	77.3		19.7
Total Acreage (millions)	27.8	100.3	46.3	7.8	18.6	200.8

Source: CPA

sedimentary area. The percentages are considerably lower for the other provinces and for the Northwest Territories for they have less sedimentary acreage than Alberta. The acreage under lease or reservation in the Western Canada basin is about two thirds of that under lease in the entire United States, excluding off-shore leases.

Oil companies, then, hold large tracts of unproved acreage which they hope to explore and develop in the future. Altogether some 500 companies hold oil and gas leases and reservations in Western Canada and more than 400 companies hold acreage in Alberta. In addition, many unincorporated businesses and individuals possess petroleum rights.

The Acquisition of Freehold Acreage

About 14 per cent of leased and reserved acreage in Alberta in 1956 had been acquired by oil companies from freeholders, chiefly the Canadian Pacific Railway Company, the Hudson's Bay Company, from some other companies such as Western Leaseholds, and from individuals, mainly farmers.

Oil companies employ the services of fieldmen, variously called leasemen or leasehounds, to negotiate with private landowners. These will be members of the land department in the case of large companies or they may be individuals who specialize in the leasing business and who are retained on fee or commission by companies or individuals. Office fieldmen look after negotiations with governments. The leasemen must be well versed in the law of property applying to the regions in which they work. Mistakes in the form of a lease or undiscovered defects in land titles can be costly.

When certain lands are deemed prospective in an area, one or more oil companies send their leasemen in to deal with individual owners. If the area is considered highly prospective, and especially if some successful wildcat wells have been drilled in it, many companies send out task forces of leasemen to sign up as many landowners as possible. Competition then becomes very keen. In Alberta, exploration and drilling on Crown reservations has usually taken place first, including operations on the surface area of private landowners. Landowners with subsurface rights will be scattered throughout a Crown reservation. Oil companies try to obtain the scattered freehold acreages in order to round out tracts obtained from the government, to secure a balanced distribution of holdings throughout a prospective or proven area.

The usual type of lease runs for a fixed term, often ten years. If oil or gas are discovered and produced, the lease runs for whatever time production takes place. An annual rental is payable, usually on an acreage

basis; this rental may run from a few cents per acre to many dollars per acre. A common figure for prospective, but unproven, freehold acreage in Alberta is $1 per acre. In proven areas it may run to $50 or more. This rental is a payment in lieu of a royalty awaiting production and it ceases once oil or gas is produced. In a sense, it is a payment for the privilege on the part of the lessee of delaying drilling. He is protecting himself from the chance that another operator will obtain and develop the properties. If the properties prove to be productive, he stands to be a winner; if not, he loses, and the funds spent constitute a part of his total cost of producing oil. Frequently, a cash bonus may be paid to the landowner at the time that he signs a lease.

The lease provides for a royalty to be paid to the owner of mineral rights in the event that oil or gas or both are produced on his land. It may be a fixed percentage or it may be on a sliding scale, providing for greater or smaller fractions related to output. The customary fraction in Western Canada is one eighth. In some leases the lessee may undertake to drill within a certain period of time and provisions may be made to drill offset wells to participate in oil production brought about by drilling on adjoining properties.

Leases are transferable by both parties and oil companies may assign, for a consideration, all or a part of the interest in them. Similarly, the lessor can sell all or part of his interest in a lease. Royalty rights are assignable and are often divided up into fractions and sold. Much speculation attends these activities during an oil boom in an area. The number of arrangements that can be made in assigning whole or partial interests in royalties and leases is legion.

The Acquisition of Government Acreage

The policies of the provincial government in Alberta are important because of its large land holdings and because of its constitutional jurisdiction over natural resources.

Reservations: All of the governments in Western Canada provide for a system of exploration permits. In Alberta the provincial government may grant applications for prospecting licenses to explore for oil and gas. The applicant applies for a reservation of exclusive oil and gas exploratory rights over an area which must not exceed a maximum of 100,000 acres and whose length does not exceed its width by more than three times. He must not hold more than two such reservations at any given time, but there is nothing to preclude a company from obtaining additional reservations through subsidiary companies, associated companies or associated individuals. Companies may also assign reservations to others without

breaking the above rules. Thus a company can arrange to carry on exploratory work over hundreds of thousands of acres. The reservation does not, however, permit drilling beyond core and exploratory drilling. For the purpose of outright drilling for oil or gas, drilling reservations or leases must be purchased.

Government regulations require the performance of a certain amount of exploratory work once a reservation is granted. The applicant pays a fee of $250 and posts a deposit of $2,500 for each 20,000 acres or fraction thereof in guarantee of performance. The reservation runs for four months after the date on which the government approves the applicant's exploration plans. He may secure two more four-month extensions without further payment if the government is satisfied with his progress. During the second year renewals may be made every three months for a fee of seven cents per acre for the first two renewals and eight cents per acre for the second two. In the third year four three-month renewals may be made provided that drilling is in progress. The fees are 10 cents per acre for the first renewal, 15 cents for the second, 20 cents for the third and 25 cents for the fourth. Further renewals may be obtained subject to the permission of the Minister of Mines and Minerals whose assent is also required if reservations are to be transferred. Altogether, on a three-year reservation, a holder will pay the initial $250 and $1 per acre for the period.

The system of petroleum and natural gas reservations was instituted in 1937, and in that year five reservations totalling 192,000 acres were taken out. The total rose to 19 reservations covering 455,000 acres in 1940. During the war years there was a great increase in exploratory activity. In 1946 the acreage reserved was more than eight million acres.

These pre-1947 acreages seemed significant at the time, but they were small compared with the levels attained since Leduc. The number of acres reserved attained a high of 48 million in 1951, six times the 1946 level. With the lack of major discoveries in 1951-53, the lack of adequate markets for crude from existing wells, and the greater selectivity in choice of reservations, acreage fell to about 24 million in 1953. Following the Pembina discovery, both the number and the acreage of reservations increased greatly in 1955 and 1956, as applications for large tracts in northern Alberta were made. Table XIII sets out data pertaining to petroleum and natural gas reservations since 1946.

Leases: If a reservation holder is satisfied with his exploratory results, he may decide to convert his reservation to a lease. He may do this at any time, and if oil is discovered in commercial quantities he must do so within three months of discovery. The lease covers both petroleum and natural gas rights and runs for 21 years, renewable for further terms of the same length as long as petroleum or natural gas is produced in com-

mercial quantity within the tract. An annual rental of one dollar per acre must be paid. The lessee must begin drilling operations within a year from the date of the lease; the machinery and equipment used must be approved by the Minister of Mines and Minerals; the lessee also must continue drilling operations according to progress and standards prescribed by the Minister.

Table XIII

Petroleum and Natural Gas Reservations Granted and Revenue Derived Therefrom by the Government of Alberta 1946-56

Calendar Year	Number of Parcels	Acreage millions	Acres per Parcel thousands	Provincial Revenue from Rentals millions of dollars	Revenue per Acre dollars
1946	86	8.6	100	0.3	0.03
1947	114	11.5	100	0.6	0.05
1948	295	23.5	79	2.0	0.09
1949	506	37.0	73	5.0	0.14
1950	502	37.1	74	8.6	0.23
1951	699	48.3	69	14.1	0.29
1952	704	41.3	59	17.8	0.43
1953	396	23.5	60	21.0	0.89
1954	547	27.3	50	24.2	0.88
1955	771	35.9	46	20.2	0.56
1956	1,051	54.6	52	24.7	0.45
				138.5	

Source: Government of Alberta, Department of Mines and Minerals.

Note: Rentals from leases are included under provincial revenue and this accounts for the high revenue per acre in 1953-54 when productive areas formed a high proportion of total acreage.

The reservation holder is not entitled to a lease on the whole reservation. The provincial government may hold back 50 per cent of the Crown mineral rights in each reservation. The number of acres available will depend upon the freehold acreage that is also within each township. The size of leases is restricted and must not exceed a rectangle four miles long and two miles wide or a square three miles by three miles.

Leases may be as small as a quarter section. The reservation holder, then, may divide up his reservation into a number of leases, not to exceed 50 per cent of Crown lands in each township. No two leases may adjoin except that they may touch at the corners.

The practice of leasing began with the establishment of a provincial department of mines and forests in 1930. In 1939 more than a million acres were under lease; the total fell in 1940-43 but rose again in 1944 and 1945. Table XIV shows the trend for 1946-56.

Table XIV

Petroleum and Natural Gas Leases, Government of Alberta, 1946-56 Number and Acreages

Calendar Year End	Number of Parcels	Acreage millions	Acreage as Per Cent of Leases and Reservations*	Acres per Lease
1946	2,685	1.1	12	420
1947	2,458	0.9	7	367
1948	4,606	2.6	10	555
1949	6,500	3.4	8	520
1950	9,351	5.8	14	615
1951	14,329	9.1	16	638
1952	20,062	14.9	26	742
1953	23,343	19.2	43	820
1954	23,207	17.5	38	755
1955	23,273	17.6	32	752
1956	24,584	19.2	26	781

Source: Government of Alberta, Department of Mines and Minerals.

*Lease and reservation acreages are exclusive.

The number of parcels and acreage leased increased remarkably in 1946-53 and then levelled off. Acreage leased was less than one sixth of total provincial acreage leased and reserved in 1946-51; it constituted about one third, more or less, during 1952-55 when reservation acreage fell off and then decreased to 14 per cent as reservation acreage increased greatly during 1956.

Sales of Crown Reservations

From time to time the provincial government conducts sales by public tender of petroleum and natural gas leases and reser-

vations. These sales are handled in three ways. First, parcels of land of up to 10,000 acres each may be offered for sale by the Mining Recorder in Edmonton or Calgary. The parcels consist mainly of the land in reservations which has reverted to the Crown and of cancelled leases. Prospective buyers must file sealed tenders together with a certified cheque for the amount of cash bonus offered for the lease on a given parcel. Following the sale the successful bidders must apply for leases on the parcels and deposit with the Mining Recorder the usual fee and lease rental for the first year. The Department of Mines and Minerals reserves the right to reject any or all offers submitted and if this right is exercised, the land is made available for direct leasing without cash bonus payments. The lands sold under this method are mainly in "proven" territory and often fetch very high prices.

Secondly, parcels of land in which the petroleum and natural gas rights have reverted to the Crown are offered regularly as reservations by public tender by the Director of Mineral Rights in Edmonton. Tenders must be accompanied by cheques for the bonus offered, together with a fee of $250 and a deposit of $2,500 for each 20,000 acres or fraction thereof. If no tenders are offered or accepted on a parcel, it becomes available as a reservation or lease on the usual terms. These sales of reservations are made mainly in "wildcat" territory which is deemed reasonably prospective for drilling.

A third method was introduced in 1954. Certain acreages called drilling reservations are offered from time to time for a cash bonus under terms which require the drilling of a test well to a specified geological formation. The cash bonus bids must be accompanied by a fee of $250 plus six months' rental at 25 cents per acre. The term of a reservation is for six months; it may be renewed for five more periods of six months each on the basis of satisfactory progress reports and on payment of 25 cents per acre for each renewal. During the first year the purchaser must begin to drill a well. If the first test well is not successful, the purchaser must begin a second well within three months. If a well comes in and commercial production of oil is indicated, a number of previously selected quarter-sections in the reservation may be leased. Expenditures for drilling test wells may be applied on the rentals for the first year.

The Alberta government, then, has worked out a system of selling oil and gas rights which facilitates exploratory work and enables it to share in successful developments. Because the company which explores a reservation has to release half of its holdings in each township, the province steadily re-acquires proven or semi-proven territory to be offered for cash bonuses to oil companies. The return of at least 50 per cent of the land to the government also prevents one company from blanketing a proven area with oil and gas leases.

During 1948, the first year that the government sold leases, a total of \$3.1 million was realized. The revenues from sales increased very rapidly but they also fluctuated in response to discoveries made. A high of \$71.7 million was realized in 1956 and all told the government received \$316 million during the nine-year period 1948-56. Table XV gives the details.

Table XV

Revenue of the Government of Alberta from the Sales of Petroleum and Natural Gas Leases and Reservations and of Drilling Reservations, 1948-56

In millions of dollars

Calendar Year	Sales of P. & N.G. Leases	Sales of P. & N.G. Reservations	Sales of Drilling Reservations	Total Proceeds from Sales
1948	3.1			3.1
1949	19.2	0.6		19.8
1950	36.3			36.3
1951	13.7	1.4		15.1
1952	22.4			22.4
1953	17.6	3.7		21.3
1954	23.8	32.9	7.2	63.9
1955	40.3	13.5	8.3	62.1
1956	66.7	1.1	3.9	71.7
Cumulative Total	243.1	53.2	19.4	315.7

Source: Government of Alberta, Department of Mines and Minerals.

The sales of petroleum and natural gas leases have produced the highest prices because they have been mainly in "proven" areas; of the total \$228 million realized, about 15 per cent was obtained from sales in unproved territory. Over the 1948-56 period, 432,000 acres were sold, about 0.6 per cent of the total area under lease and reservation on September 30, 1956. It is on these acres plus freehold productive land that most of the oil fields of Alberta are located. The average price rose from \$120 per acre in 1948 to \$892 in 1950 when many parcels were sold in the rich Redwater field. A new high of \$1,200 was reached in 1956. The average price per acre for the whole 1948-56 period was \$530. Prices exceeding \$10,000 per acre and even over \$20,000 were paid for some parcels.

The prices per acre of petroleum and natural gas reservations, chiefly in unproved territory, and for drilling reservations were much less than those paid for leases in proved territory. Thus a total acreage of 3.7 million of petroleum and natural gas reservations was sold at an average of $15 per acre in 1949-56, ranging from less than $1 in 1952 to $36 in 1954.

Table XVI

Cumulative Revenue from Cash Bonuses Paid for Crown Lands in the Major Oil Fields of Alberta, 1948-56

Field	Total Cash Bonuses millions	Acres Sold by Crown thousands	Price per Acre	Percentage of Crown Land Production of Total Crude Oil Production, 1954
Pembina	$ 77.7	44.1	$1,760	92
Redwater	54.1	16.0	3,380	87
Sturgeon Lake[1]	15.1	5.8	2,600	100
Fenn-Big Valley	9.7	4.5	2,170	43
Leduc-Woodbend	7.8	13.8	570	56
Joarcam[2]	6.3	4.3	1,460	47
Bonnie Glen	4.5	1.0	4,650	32
Total, Seven Fields	$175.2	89.5	$1,960	64
All Proven Areas[3]	190.0	139.1	1,360	62
Total, All Areas	228.3	431.5	530	62

[1]Includes Sturgeon Lake South.

[2]Includes Joseph Lake, Armena and Camrose.

[3]Totals were derived by subtracting "sales in other areas" from all sales of leases.

Source: Government of Alberta, Department of Mines and Minerals.

Drilling reservation prices averaged $17 per acre for 1954-56, from $6 in 1956 to $48 in 1954. The prices bid for the latter have dropped sharply since 1954.

Among the oil fields of Alberta, Pembina leads with total cash bonuses of nearly $78 million up to September 30, 1956, followed by Redwater with $54 million. Returns from the first major oil field, Leduc-Woodbend,

seemed large in 1948-50, but amounted to only $8 million; this was small compared with Pembina and Redwater where the Crown controlled a much larger part of the acreage. There were large private holdings in the latter while freehold acreage was almost negligible in the former fields. Table XVI shows the returns from cash bonuses for leases in the major oil fields of Alberta. These fields also provide annual lease rentals revenue and royalties from production. In 1955, more than nine tenths of crude-oil production in the Pembina field was from Crown lands; the fraction was almost nine tenths in the Redwater field. It was only about 55 per cent in the Leduc-Woodbend field and slightly less than 50 per cent in the Joarcam field. Altogether, about three quarters of production came from Crown lands, mainly because the Crown holds almost all the land in the two most productive fields, Pembina and Redwater.

Natural Gas Licenses and Leases

Until the 1950's, the main incentive to exploration and drilling was the prospect of discovering oil. With the change in the gas export policy of the Alberta government in 1952, the outlook for natural gas brightened. Consequently, oil and gas companies began to take out natural gas licenses and leases quite apart from the traditional petroleum and natural gas reservations and leases.

Under regulations set out by an order-in-council of the province in 1951, the holder of a reservation of petroleum and natural gas rights may apply for a license limited to the natural gas rights in a reservation where he has discovered natural gas. The license fee is $250 and the rental five cents per acre for six months. Renewals may be made every six months for a total of three years at a rental of five cents per acre for each six-month period. These licenses may also be obtained in areas where natural gas has not been found. They grant the privilege of drilling for natural gas and this must begin within three months after the granting of the license. The licensee has exclusive rights before the termination of the license to apply for a natural gas lease which runs for 21 years, renewable for further terms of 21 years each for so long as the area produces gas in commercial quantity. The lease covers natural gas rights only and the annual rental is 10 cents per acre until an adequate market is available when it becomes 33⅓ cents. If oil is discovered while drilling for gas, the licensee or lessee may apply for a lease of the undisposed petroleum and natural gas rights in the quarter-section parcel in which the discovery is made provided that he surrenders certain parcels designated by the Minister of Mines and Minerals out of his license or lease. Natural gas licenses and leases are also sold by cash bonus tenders.

There were no provincial government revenues from natural gas licenses and leases before 1951. During 1951-56 more than one million dollars have been obtained from natural gas rentals and more than three million dollars in cash bonuses from the sales of leases and rentals. These figures, of course, are small beside the hundreds of millions of dollars obtained from the rentals and sales of petroleum and natural gas leases.

For the ten-year period of 1947-56 the Alberta government has collected more than $300 million from the sale of leases and reservations of all kinds and almost $140 million from rentals on leases for a total approaching $460 million. The following table shows the total revenue collected by the Government of Alberta during the decade 1947-56 from oil and gas rights:

In millions of dollars		
Petroleum and Natural Gas Reservations		138.2
Natural Gas Reservations		1.2
Sales of Crown Reserves:		
Petroleum and Natural Gas Leases	243.1	
Petroleum and Natural Gas Reservations	53.2	
Drilling Reservations	19.4	
Natural Gas Licenses	3.4	
Natural Gas Leases	0.3	319.4
Total		458.8

The total for the decade averaged more than $400 per person in Alberta and it was almost one third of all the revenue collected by the provincial government in 1947-56. The implications of this flow of dollars into the Alberta treasury are many and they will be explored elsewhere.

Royalty Payments to the Government

Once production of oil, gas and other petroleum products commences, royalties are payable. At present in Alberta, the Crown royalties on crude oil are computed on the monthly production of a well, with greater or smaller amounts being required according to the level of output. The schedule on p. 196 sets out the rates payable in 1957; these rates were established on June 1, 1951.

In effect, the higher the rate of production, the greater the percentage

payable in royalties and vice versa. The small royalty payable on the output of wells producing at a low rate helps to make the operation of such wells economical; a large royalty on the output of such wells might prohibit their operation entirely.

Monthly Production	**Crown Royalty**
0- 600 barrels	*5 per cent of total output*
600- 750 barrels	*30 barrels plus 14 per cent of output over 600*
750- 950 barrels	*51 barrels plus 17 per cent of output over 750*
950-1150 barrels	*85 barrels plus 18 per cent of output over 950*
1150-1500 barrels	*121 barrels plus 19 per cent of output over 1,150*
1500-1800 barrels	*12½ per cent of total output*
1800-4050 barrels	*225 plus 20 per cent of output over 1,800*
4050 and over	*16⅔ per cent of total output*

The Crown royalty on natural gas production is 15 per cent of the selling price at well-head with a minimum of 0.75 cents per thousand cubic feet of gas sold. The rate is a flat 12½ per cent on other hydrocarbons and sulphur. No royalty is payable on natural gas or residue gas used for drilling or production purposes on the location. Some of the leases sold by public tender also provide for an overriding royalty of 15 per cent on crude oil production over and above the rates set out above.

Royalties on crude oil production from freehold properties are usually 12½ per cent of output. Furthermore, there are apportionments of royalties when companies make farmout agreements and there are many agreements involving gross and net royalties.

The Income Effects

Since most of the petroleum rights in the province were held by the provincial government, there was a marked effect upon the provincial treasury. Receipts from the sale of leases and from rentals of oil and natural gas acreage currently provide about two fifths of the revenue of the provincial government. Of the total funds spent by the industry on the acquisition of acreage in the province currently, only one tenth has been paid to non-residents in recent years. The fraction was higher during the first half of the "oil decade" when fields with rather large freehold and corporate holdings were prominent. The following table sets out estimated allocations of land acquisition expenditures among Albertans and non-residents in 1947-56:

In millions of dollars

	Alberta Crown	Alberta Free-Hold and Indian	Total Alberta	Non-Residents*	Total
1947	1	2	3	2	5
1948	5	4	9	3	12
1949	25	4	29	3	32
1950	45	8	53	4	57
1951	30	9	39	5	44
1952	40	7	47	10	57
1953	44	4	48	9	57
1954	89	5	94	10	104
1955	83	6	89	11	100
1956	98	9	107	13	120
	460	58	518	70	588
Per Cent of Total	78	10	88	12	100

*Chiefly the Canadian Pacific Railway, the Hudson's Bay Company and the Calgary and Edmonton Corporation.

The provincial government utilized the funds it received to pay a growing civil service, construction workers and contractors engaged in providing public buildings and highways, and grants and loans to local governments which in turn spent the receipts to remunerate an increasing number of employees and workers engaged in the construction and other industries. These expenditures of the regional governments generated further income in consumer goods and housing industries, widening the stream of income injected initially by the petroleum industry. The government used some receipts to build up cash balances and to reduce debt; this reduced the effect of the land payments upon income generation in the province. However, liquidity of the governments increased and the receipts from the petroleum industry enabled the regional governments to provide a rising level of services without corresponding increases in provincial government taxes.

The contribution of petroleum land expenditures to income in Alberta rose from less than one per cent to almost one tenth in 1947-56. Currently, then, almost one Albertan out of ten is dependent upon the spending of the provincial government and freeholders from land receipts furnished by non-residents.

It is notable that the number of provincial government employees has almost tripled since 1946 and its payroll has more than quadrupled. Similar observations apply with respect to municipal governments, particularly the urban ones. Probably an estimated 10,000 provincial and

Table XVII

The Income Contribution of Petroleum Industry Expenditures on Land in Alberta, 1947-56

In millions of dollars

	From Government Receipts[1]	From Private Receipts[2]	Total
1947	1	3	4
1948	7	7	14
1949	25	6	31
1950	46	12	58
1951	36	14	50
1952	40	12	52
1953	48	6	54
1954	120	8	128
1955	104	10	114
1956	128	14	142

[1]Estimated from government receipts. The receipts were reduced by the portion furnished by Alberta residents through their contributions to petroleum industry funds, by the degree to which the government built up cash surpluses or repaid debt, and by the import content of government expenditures. The resulting estimate in each case was multiplied by the generative ratio which fell from 2.3 to 2.0 during the decade.

[2]The receipts were reduced by the portion furnished by Alberta residents through their contributions to petroleum industry funds and the resulting estimates multiplied by the usual generative ratio.

municipal government workers as well as workers in industries supplying the governments with materials and equipment were added to the Alberta labour force in 1947-56 because of receipts from petroleum land sales and lease rentals. It is estimated that each of these workers required the addition of two workers in industries providing consumer goods and serv-

ices. This implies that an additional 20,000 jobs were created in these industries. All told, the land receipts added an estimated 30,000 workers to the Alberta labour force during the decade. Each of these workers supports, on the average, nearly three persons including himself, thereby accounting for a population increase in the province of about 80,000. The full employment effects of the petroleum industry activities are dealt with in a subsequent chapter. The above example is illustrative of the character and degree of economic growth in Alberta since 1947.

17.

Conservation and Prorationing

We have made many references to the Alberta Petroleum and Natural Gas Conservation Board. It was established in 1938 to deal with excessive flaring of gas in the Turner Valley field and to control production of crude oil wells. Its work has expanded greatly as it has become involved in establishing good drilling and production practices, in prorationing oil production and in conducting hearings on the question of gas exports. Its powers and jurisdiction are very wide under the provincial act which established it.

The board has drawn heavily upon the experience of the petroleum industry in the United States and this has assisted it in avoiding detrimental engineering and marketing practices. There are three members, Mr. I. N. McKinnon, an accountant, who serves as chairman; Mr. D. P. Goodall, a petroleum engineer, who is deputy chairman; and Dr. G. W. Govier, the head of the Department of Petroleum Engineering at the University of Alberta. All the members have had many years of experience in matters pertaining to petroleum. There is a staff of engineers, statisticians and clerical workers. District engineers are posted in various fields throughout Alberta.

To provide funds for the board, a property tax is levied on oil-producing areas and this is paid by the companies holding mineral rights. Nominally, this levy is to meet 60 per cent of the cost with the provincial government contributing the balance. Appointments to the staff are decided upon by the board and so are salaries; it was found that the regulations pertaining to appointments and salaries of the Alberta Civil Service were not flexible enough to permit the board to obtain qualified engineers and people with experience in the petroleum industry.

Drilling and Production Regulations

The board exercises close supervision over the drilling of wells. If an operator anticipates that a well is to be drilled to a depth in excess of 500 feet, he must apply for a license. If the board approves, the license is issued by the Minister of Mines and Minerals. The operator must satisfy the board that he has obtained the right to enter the land from the landowner and that his oil and gas rights on the property are in order. He must also specify the location of the well very precisely. The board also has an elaborate set of rules requiring a driller to cut cores at stated intervals in exploratory as well as development wells, to maintain a record of electric logs and daily drilling reports, and to collect samples of oil, gas and water as drilling proceeds. A field staff of geologists and petroleum engineers examines cores and logs while oil, gas and water samples are analyzed in the laboratory of the board. Maps are prepared and statistical data on production and reservoir factors are collected. Much of this information is published for use by the industry in annual, monthly and weekly reports. We have already noted the *Schedule of Wells Drilled* which has been published annually since 1949. Data collected with respect to wildcat wells are kept confidential for a year.

Well-spacing is regulated by the board and it is customarily 40 acres per well, now a common spacing unit in the United States. In fields with good permeability and strong reservoir drives spacing may be 80 or even 160 acres per well. For example, it has been suggested that ultimate recovery would be just as great in the Redwater field with one well per 160 acres as with the actual one per 40 acres. Such spacing would have saved large expenditures on drilling. In the heavy oil fields like Lloydminster a spacing of 10 acres is permitted because permeability is poor and the reservoir drives are weak. In gas fields, a spacing of one well per 640 acres is standard because gas travels through formations much more readily than oil.

The board has made it a practice to work out the maximum production rates, usually called "maximum permissible rates" or MPR's, for fields and pools. This is in the interests of conservation and the MPR per well of a pool is the board's engineering estimate of the individual well's maximum efficient rate of production. This producing potential is really a physical conservation maximum which should not be exceeded in the interests of long-term production. The MPR's of the wells in a pool represent the potential (the term used is "producibility", a word which cannot be found in the dictionary) which would be permitted from a

conservation point of view if markets could absorb that level of output. To date, the "producibility" of Alberta fields and pools has continuously exceeded actual production because of market limitations.

The board determines MPR's on a tentative basis during the early life of a pool because of lack of information at that stage on the size and characteristics of the reservoir. Gradually, as information becomes available, about a dozen variables are considered. These are acreage, pay zone thickness, porosity, connate water, shrinkage, nature of the reservoir drives, expected recovery factor, expected life of the pool, the degree of development of the pool, reservoir pressure, producing gas-oil ratio, and producing water-oil ratio. Some of these variables are interrelated; for example, the expected recovery and life of the pool depend partly upon the nature of the reservoir drive. The variables are combined into a formula whereby MPR's are calculated. The MPR's are recalculated from time to time because some of the variables obviously change with the passage of time. It should be clear, too, from our previous examination of basic reservoir factors in estimating reserves that the MPR per well varies greatly from field to field, from a few barrels per day to hundreds of barrels per day.

The board conducts hearings at least twice a year to obtain submissions from companies with respect to reservoir characteristics. From the data so submitted and from the data provided by its own engineers, the board then applies its formula in each case.

Prorationing to Market Demand

Crude oil is produced and sold by a large number of operators who are anxious to recoup land, exploration, drilling and other development expenditures. It is bought by the relatively few refining firms in the industry who periodically nominate the amounts they desire to buy. As long as supply and demand conditions are stable, there is not much trouble in adjusting production to the quantities nominated by buyers. But supplies are usually in excess of the quantities demanded. This is part of the nature of the oil industry. It must look for oil continuously to assure supplies for years ahead. Furthermore, discoveries often come in large increments; when a major field is discovered, market outlets and transportation facilities become inadequate in the short run. In the early history of the industry there are numerous instances of price cutting by producers who attempted to market their potential output, and the results have always been disastrous for many producers. The communities concerned have also suffered from the resulting instability. To overcome the fundamental instability of crude oil supply and demand

equilibrium, a device termed "prorating" in the United States and "prorationing" in Alberta has been worked out.

In Alberta prorationing to market demand is of fairly recent origin. Large purchasers of crude oil attempted to do their buying on a quota basis from producers in the Turner Valley field prior to 1938. The Conservation Board then came into the picture and it worked out a system of maximum production rates (MPR's) for the different wells in the field. These rates were set with a view to achieving maximum ultimate recovery. Prorationing to achieve equity among producers did not prove necessary because the market expanded greatly during the war.

After the Leduc discovery prorationing became urgent because the production potential increasingly outstripped the quantity that could be marketed. Until 1949 producers managed to sell all the oil they were permitted to produce. This state of affairs changed materially in 1949 when the prolific Redwater field began to make its potential felt. In the spring of 1949 the purchasing companies had to set up a system of well acceptances under which quotas purchased ran below the MPR's, and for the year actual production ran at about only two thirds of "producibility". Matters became even worse in 1950 with the continuing intensive development of the Leduc-Woodbend and Redwater fields and actual production for the year fell to one half of producibility as defined by MPR's. It was impossible for the purchasing companies to set up a well-acceptance system acceptable to all producers under these conditions and a number of them complained of inequities within pools to the Conservation Board which was requested to work out a marketing scheme.

The Oil and Gas Resources Conservation Act was amended by the provincial government to give the board the power to deal with the matter, and in October, 1950, the board held a public hearing at which producers and purchasers submitted their views and suggestions on prorationing. From the information obtained, the board worked out a prorationing formula which has remained basically the same since December, 1950, when it was put into effect.

Two procedures are involved in applying the formula each month when allocations are made. The first is to estimate the demand for Alberta crude oil, and this is done by requiring purchasing companies to submit monthly nominations of their crude oil requirements for the subsequent month. This establishes the quantity of oil which can be sold. The second task is to divide this quantity among fields, pools and wells according to a formula which prorates the demand on the basis of two factors called the "economic allowance" and the "prorated share".

The economic allowance is a factor worked out on the basis of cost considerations and its adoption by the board grew out of two cost principles suggested by producers at the initial hearings. One was that a

minimum allowable rate of production should be set for every producing well and that it should yield a return sufficient to meet operating costs plus a return on the capital investment. The other cost principle suggested was that the market allowable should take into account the cost of drilling a well. The board accepted the idea of a minimum production per well, even if it exceeded the MPR, and it worked out "economic allowances", that is, minimum allowable rates based on drilling and other costs. The results are illustrated in fig. 46 which shows the economic allowance per well in various Alberta fields in 1955. The minimum is 30 barrels per day and increases with well depth, giving wells in fields like Rimbey and Sturgeon Lake where drilling depths are around 9,000 feet an economic allowance of 50 barrels per day more. Drilling depth is the primary factor governing the economic allowance, but it is modified by adjustments for ease or difficulty in penetrating formations and for differences in producing conditions. The result of the application of the principle of an economic allowance is that some wells are allowed to produce at rates exceeding their MPR's.

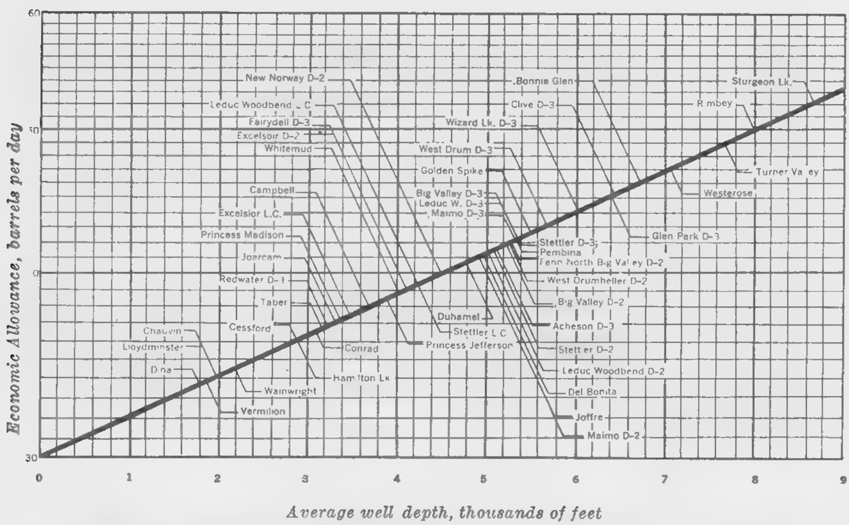


Fig. 46 Economic allowance chart, 1956. Schedule No. 1 to proration plan
Source: PNGCB

The "prorated share", the second element in the prorating formula, is determined by the MPR's. The production potential of each pool is worked out as a percentage of total provincial potential. This percentage is then used to ration production in accordance with total market require-

ments. There are several methods used to compute the producing potentials. The MPR of a pool may be calculated without reference to the individual wells. In some pools, well MPR's are calculated and adjustments made in computing the pool potential since some wells cannot produce at the MPR rate. Finally, some pools are in the stripper stage of production (e.g. Turner Valley) and have neither well nor pool MPR's. In such cases the board permits production in accordance with good field engineering practice and an estimate of the pool's "producibility" is made.

The economic allowances are subtracted from the total amount for which there is a market and the residual is distributed as "prorated shares". If a pool cannot produce its economic (minimum) allowance, the pool potential only is subtracted in determining residual demand. A number of adjustment factors are used at the discretion of the board to deal with special cases. Well operators are notified monthly of the amounts they may produce by means of a board order approved by the provincial government.

Table XVIII illustrates the results of the board's formula for some selected pools in December, 1956. The lowest economic allowance for any pool is 34 barrels per day, typified by Chauvin and Wainwright which have shallow wells. The Chauvin MPR is below 34 barrels but a market allowance equal to the economic allowance is permitted. The highest economic allowance is typified by Sturgeon Lake where wells are deep. Market allowances run as high as 352 barrels per day as in the Wizard Lake field.

In establishing the prorated outputs of pools and wells, pools are classified according to the API gravity of their crude. The pools of the province are designated as producers of heavy, medium and light gravity crudes. When making nominations purchasing companies designate the type of crude they desire and the board then sets up three classes of crude, classifies the fields and prorates accordingly. The board has considerable leeway in its definitions. The definitions of "medium" gravity crude caused much difficulty, and to prevent constant hearings on the matter the board was simply given the authority to define "medium" crudes as "crudes which from the over-all refining viewpoint, after giving consideration to gravity, sulphur and distillation characteristics, are considered intermediate between the light and heavy categories" and "to use its judgment each month in allowing the border-line crude to the particular category which in its opinion results in the most equitable proration of the over-all demand". The board, however, continued to have difficulties with the "medium" category, and within two years only one field was included in it. The "heavy" category has caused relatively little difficulty, for during much of the period since 1950 nominations

have been sufficient to absorb the quantities produced. Both drilling and production (by pump) tend to be adjusted fairly easily to increases in demand.

Table XVIII

Economic Allowance and Market Allowables, Selected Alberta Oil Fields, December, 1956

In barrels per day per well

	Economic Allowance	Market Allowance	API Gravity of Oil
Bonnie Glen	46	209	35°–43°
Chauvin	34	34	23°
Fenn-Big Valley:			
Nisku (D-2)	42	89	30°–34°
Leduc (D-3)	42	42–64	28°
Joarcam	37	37	37°
Joffre	41	41	40°
Leduc-Woodbend:			
Nisku (D-2)	41	41	39°
Leduc (D-3)	42	77	39°
Lower Cretaceous	39	39–55	39°
Lloydminster	34	34	9°–19°
Pembina (Cardium)	42	83	37°
Redwater	37	99	35°
Rimbey	50	140	39°–41°
Sturgeon Lake	52	89	35°
Wainwright	34	(a)	18°
Westerose	47	(b)	40°
Wizard Lake	44	352	36°

Source: PNGCB.

(a) No market allowable set with production to be guided by good field practice.

(b) A unitized field with no well allowables but with a pool allowable.

We can now summarize the prorationing steps. The total demand for Alberta crude is estimated from nominations; this total is divided into three categories, light, medium and heavy, and pools are assigned to one of these categories. The economic allowances and the MPR's for each pool and category are calculated. The economic allowances in each category are subtracted from the total demand for each category of oil. The

residual demand is then distributed among the pools capable of producing oil in excess of their economic allowance, that is, among the pools whose MPR's exceed their economic allowances. The prorated share of each pool is determined by its percentage "producibility" in relation to total provincial "producibility" of pools in the category. The economic allowance and the prorated share in each pool are added to arrive at the market allowance. In the interests of conservation, the well market allowables may be adjusted during the month if the gas-oil ratio exceeds 1,000 cubic feet per barrel, with certain exceptions, or if the water-oil ratio climbs above 0.2 barrels of water per barrel of oil.

If the number of wells coming in as producers increases and nominations do not increase, market allowables decrease. A greater portion of the demand is then supplied by the economic allowance and the prorated share decreases. On the other hand, if the quantity demanded increases and the number of wells were to remain constant for a month, the prorated share would increase. Market demand rises to a peak during the summer months and the prorated share may then rise to as much as one half of the total allowable production. In the winter, market demand falls off and the prorated share may shrink to about one quarter of the total allowable. The proportions change, too, from year to year as there are uneven increases in demand and new discoveries.

The board has an enforcement staff which supervises production. Overproduction in excess of 10 per cent of the monthly allowable is penalized by cutting back quotas in subsequent months. In cases of underproduction the board permits up to 20 per cent of a month's allowable to be carried forward to the next month. Special dispensations are provided if exceptional circumstances necessitate overproduction or underproduction. For example, pipe line and storage facilities in a field may be inadequate temporarily or road conditions may preclude the movement of oil in fields not served by pipe line during rainy periods in the summer or snowbound periods in the winter.

Currently the prorationing formula is being subjected to study by the board in the light of past experience and submissions by oil companies at a recent MPR hearing. It is expected that the formula will be modified somewhat in the near future.

Field Unitization

Field unitization is an arrangement whereby the wells in a field are operated under a common management. This permits the application of good engineering practices to the whole field because special concessions, such as economic allowances for pool wells, need

not be made. Only the number of wells required to obtain desired recovery need be drilled, and field development generally can be facilitated by unitization. A field which is operated by one company only is a unit, but this is a rare occurrence. Unitization generally means that a group of operators draws up an agreement whereby a pool is operated by a committee chosen by the operators. Too often unitization is blocked by one or two or a few operators or royalty owners who think they have much to gain by remaining independent or much to lose by unitization. Royalty owners seem to be even more difficult to deal with in this matter than operators.

Few Alberta pools were unitized, and the chief example is Westerose where British American, California Standard, Husky, Phillips and other companies have a pooling agreement. A number of attempts have been made to unitize other fields, but the opposition of a few parties, often with small interests, has prevented the working out of agreements.

During the 1957 session of the Alberta legislature, the Oil and Gas Conservation Act was amended to provide for compulsory unitization where requested by the owners of more than 50 per cent of the interest in a pool and if deemed to be "in the public interest" by the Conservation Board. Many oil companies had complained that one or two producers in a pool can take advantage of the others by virtue of the special locations of wells in the area. To meet this problem the government responded with the 1957 amendment. When the operators in a pool cannot agree unanimously to unitize it, the board will hear an application of 50 per cent or more of the owners (as based on their acreage interests) for unitization as well as hear the representations of the other owners. If unitization is undertaken, the companies involved will share operating and capital expenses on a basis determined by the board. If an operator should fail to pay his share, the unit operating committee will have the power to collect from his share in production and to take a first lien on his equipment. By and large, the new amendment represents an adjustment desired by most operators in the industry. Several important pools have already been unitized.

The Canadian Petroleum Association

The Canadian petroleum industry has an organization called the Canadian Petroleum Association which has its roots in several groups formed in Alberta during the 1920's and 1930's. Its aims are to provide the general public with information about the industry, to make representations of the industry to governments, to provide a medium through which members of the industry can discuss their prob-

lems and, in general, to promote the welfare of the industry. The association has a large number of standing committees on a variety of matters from leasing regulations to income taxes. It also collects data on petroleum industry activities and publishes statistical and other reports.

A great problem of the association is the diversity of interests of the members who consist of large integrated companies as well as small independents. Therefore, unanimity is not easily achieved with respect to policy matters or submissions to the government. But the process of discussion among the various groups assists in promoting understanding to a point where problems are resolved within the industry rather than by recourse to governmental judgment.

Summary

The provincial government has a large stake in the petroleum industry of the province. The treasury has benefited greatly from land and royalty payments, and currently they provide about half the revenue of the government. The land and conservation regulations of the province are deemed to be as good as or even superior to the regulations of any other province or state. The regulations and the way in which they are administered protect the interests of the citizens of Alberta and, at the same time, are not so stringent as to discourage the petroleum industry from investing in the province. The government seeks to secure the greatest revenue possible from the industry and to encourage a continuous flow of expenditures on exploration and development. The record of the last ten years demonstrates a high degree of success in achieving these objectives. An assessment of the future implications of policies is beyond the scope of this volume and would constitute a special study in itself.

18

The Petrochemical Industry Comes to Alberta

The word "petrochemical" is almost as new as the burgeoning industry which it describes. It was coined during the Second World War to designate chemicals made on a commercial scale from petroleum and natural gas.

The new term causes some difficulty because of its looseness. Gasoline, for example, is not a petrochemical while polyethylene is; sulphur derived from petroleum and natural gas is a petrochemical, but if it is produced from other substances it is not. Here we have both a semantic and an epistemological question which would delight a scholastic academician. As neat a definition as any, if one is required, is that of Donald Quon, University of Alberta petroleum engineer. A petrochemical is "a chemical that is produced from petroleum and natural gas, or their products, but which is not used for fuel purposes". For practical purposes, the list of petrochemicals includes such substances as carbon black, sulphur, synthetic rubber, polyethylene, formaldehyde, polystyrene, glycols, isopropyl alcohol, acetone and cellulose acetate. This list is by no means exhaustive. These substances are in turn made into clothing, soaps, rubber goods, building materials, drugs, packaging materials and so forth.

The raw materials used in producing petrochemicals consist of natural gas and certain refinery products. Components of natural gas which are used are methane, ethane, propane, butane and hydrogen sulphide. Sulphur is included as a product of the industry even though it is not a hydrocarbon, because it is a derivative of hydrogen sulphide, a com-

ponent in varying quantities, of natural gas. These are readily available in Alberta in quantities of natural gas more than sufficient for manufacturing purposes; the amounts required as raw materials are small relatively to those used for fuel. Refinery products used are off-gases such as ethane-ethylene, propane-propylene and butane-butylene and petroleum fractions such as aromatics. Aromatics, by the way, are hydrocarbon compounds having closed, ring-like molecular structures and characterized by a relatively high carbon-to-hydrogen ratio. Common examples are benzene and toluene. These substances provide the raw materials for the petrochemical industries established in the two great refining centres of Canada, Montreal and Sarnia. The Alberta industry is largely based upon natural gas, supplemented by refinery products.

The Growth of the Petrochemical Industry

The petrochemical industry is young. It was only about 30 years ago that chemicals first began to be produced from petroleum in the United States. In this interval the industry there has grown to major proportions with much of it concentrated in the Gulf Coast region which possesses large refining facilities, low-cost supplies of natural gas for raw material and fuel uses, and water transportation. Between 1940 and 1956 the capital investment in the industry rose from $350 million to about $4.3 billion while the value of annual production increased from less than $100 million to more than three billion dollars. Chemicals derived from oil and natural gas currently provide practically all of the butadiene requirements for synthetic rubber and large proportions of plastics, synthetic detergents, nitrogen for fertilizers, ammonia, synthetic fibres and insecticides. In the United States the output of petrochemicals jumped from 75 tons in 1925 to more than 15 million tons in 1956. Fig. 47 portrays the rapid growth of the industry in terms of per capita production.

The industry had its roots in the synthetic organics industry whose raw material originally was coal. Crude oil and natural gas were found to be superior to coal in many respects. They have higher hydrogen-to-carbon ratios than coal; they lend themselves to processing by a variety of fairly elementary chemical routes; they are easily handled and transported. Finally, they are relatively cheap. Crude oil is particularly valuable since it is even more versatile than natural gas as a starting material for the manufacturing of petrochemicals.

In Canada the industry obtained its beginnings in Sarnia from the stimulus of war; in Alberta it has had a life of not much more than five years. Investment in the Canadian industry grew from practically nothing

in 1939 to more than $50 million by 1943 and to more than $80 million in 1950. With the construction of major plants in Alberta during 1951 and 1952 and of extensions and new plants in Eastern Canada, it exceeded $200 million by 1952. Currently it stands at $350 million of which about 45 per cent is located in Alberta. At least 20 companies make more than 40 petrochemicals.

Here we shall only glance at the development of petrochemical plants in Eastern Canada before turning to Alberta. The pioneer firm was Polymer Corporation, a Crown corporation set up in 1942 by the federal government to produce synthetic rubber for wartime needs. It was located at Sarnia where there was a large oil refinery, an abundance of

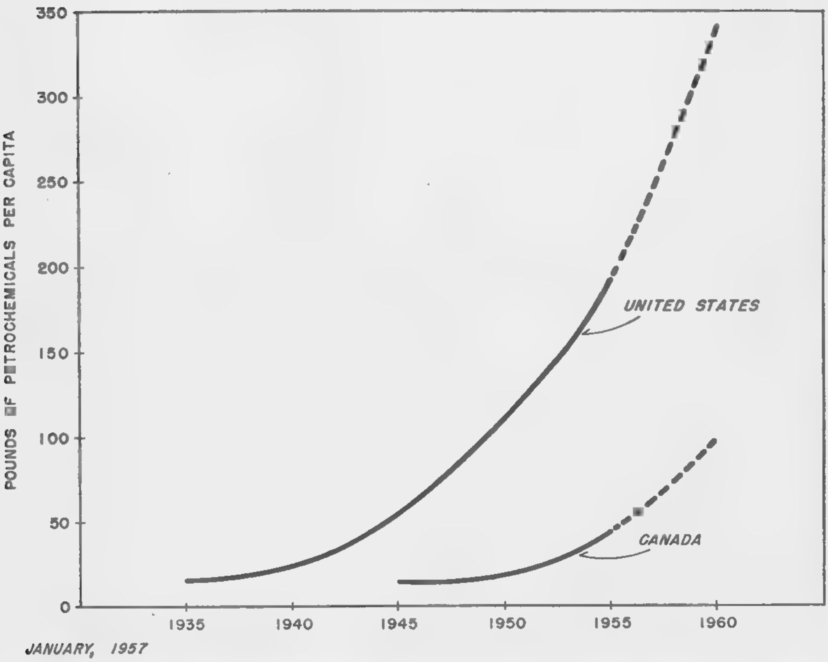


Fig. 47 Per capita production of petrochemicals, United States and Canada

water for industrial use, and low-cost water transportation. Furthermore, Sarnia was close to the main Canadian rubber-consumption centres. Since 1951 Alberta oil has made Sarnia the "chemical valley" of Canada. A number of companies have established petrochemical plants there. The story of Polymer's development is told in detail in *The Canadian Petrochemical Industry,* an excellent reference book on the industry published by the Shell Oil Company of Canada in 1956, in which the developments

of various other firms are also discussed. Plants have also located in other parts of Ontario and in the Montreal area, a great refinery centre.

Firms in the petrochemical industry are increasingly attempting to integrate their operations to diversify their product lines and to set up effective sales organizations. Competition is keen, much keener than several years ago, as more and more firms undertake to produce a given product such as ammonia or plastics. Competition also arises from firms outside the industry which make similar products with non-petroleum raw materials. The prices of a number of products have tended downward since the end of the war, despite the general inflattionary trend since 1946. Earnings of companies, even the Big Four in the United States, Dow, Du Pont, Monsanto and Union Carbide, are far from assured from year to year.

The Rise of the Petrochemical Industry in Alberta

The petrochemical industry in Alberta dates back to 1940 when an ammonia and ammonium nitrate factory was built at Calgary, using natural gas as the raw material, the first major plant on the continent to do so. The Canadian and United Kingdom governments financed the plant jointly to a total of $11.75 million. The Alberta Nitrogen Company was incorporated to construct and operate the plant through the use of the management and technical personnel of Canadian Industries Limited and the Consolidated Mining and Smelting Company of Canada, who became the guarantors and the only shareholders of the new company. The plant was completed in late 1941 at a cost of $7.1 million and an output of 130 tons of ammonia per day was soon achieved. Much of it was converted into ammonium nitrate in Calgary and at Trail, B.C., and most of the rest was shipped to explosives plants in Winnipeg, Eastern Canada and the United States. The venture proved to be very successful financially because of the low cost of natural gas at Calgary and the high wartime demand which kept the plant operating at full capacity. During 1942 the ammonia capacity was increased and facilities were installed to produce ammonium nitrate at a total cost of $2.0 million. The "prilling" process for treating ammonium nitrate fertilizer was worked out in 1943. This consisted of producing the nitrate in the form of small free-flowing pellets to overcome caking in bags. Markets for the fertilizer were developed in the United States, Europe, Africa and even the Orient. Currently almost 95 per cent of the output of fertilizer is sold in the United States to farmers and the balance is sold in Canada. The ammonia produced in the plant but not converted to nitrate is

shipped to fertilizer plants at Kimberley and Trail in British Columbia.

The Calgary plant was sold to The Consolidated Mining and Smelting Company of Canada in May, 1946. Again, the capacity of the plant was increased in 1953 to produce 200 tons per day of ammonium nitrate, about one half of Canadian capacity. Ammonia capacity was increased to 260 tons daily by 1955 and further expansion to 390 tons per day is under way. A urea unit is also planned.

A second ammonia plant utilizing natural gas was built at Fort Saskatchewan, about 15 miles northeast of Edmonton, by Sherritt-Gordon Mines Limited in 1954. This is primarily an intermediate processing plant utilized by the company to leach ore concentrates. Nickel-copper-cobalt-iron sulphide concentrates are shipped by rail from the Sherritt-Gordon mines at Lynn Lake, Manitoba, to the Fort Saskatchewan plant in Alberta. Here the concentrates are leached under pressure with ammonia and air, removing iron, silica and other impurities. Then copper sulphide is separated from the solution and most of the nickel is precipitated by hydrogen under pressure. About 94 per cent of the nickel in the ore is recovered and it is all sold under contracts with the United States government and four United States steel companies. The cobalt residue is sold and shipped elsewhere as a concentrate to be refined, but this practice will cease as soon as a cobalt recovery unit is built at the Fort Saskatchewan plant. The copper sulphide is shipped to Eastern Canada for smelting and electrolytic refining. Any ammonia not required for the metallurgical processes is sold for fertilizer processing. Here, then, is another Alberta plant whose output goes almost exclusively to markets outside Alberta. This plant is also unique in that it primarily performs an intermediate process in the production of metals which become well travelled by the time they are put to their end-uses.

The Fort Saskatchewan plant had an initial rated capacity for producing 75 tons of ammonia and two tons of hydrogen per day and processing annually 8,500 tons of nickel, 975 tons of copper and 125 tons of cobalt as well as for producing 65,000 tons of ammonium sulphate as a by-product. More than eight million cubic feet of natural gas are used per day both as raw material and fuel, and this is supplied by a new natural gas company, Mid-Western Industrial Gas Limited. The Calgary Power Company provides the power. Altogether, including a river pumping station and a cooling tower, the plant cost $24.2 million. An extension was constructed in 1957. The plant began operations in May, 1954, and the facilities have been taxed to the limit during most of the time.

A third ammonia plant was completed at Medicine Hat in 1956 where the Northwest Nitro-Chemicals Company constructed a $22-million structure. It will obtain natural gas from adjoining fields to be used as

fuel and as raw material for manufacturing ammonia, high-analysis nitrogen and phosphate fertilizers.

By 1957 Alberta had an investment of about $60 million in ammonia plants, representing more than half of the Canadian capacity. The fundamental factor underlying this development is the abundance of low-cost natural gas in the region.

The largest petrochemical plant in Alberta in terms of investment, and almost equal to Polymer which is the largest in Canada, was completed by the Canadian Chemical Company in 1953. It is estimated to have cost $70 million and produces a wide variety of products. Strictly speaking, since much of the output consists of cellulose acetate and yarn, part of it belongs to the textile industry and is so classified by the Dominion and Alberta Bureaux of Statistics. The plant has a floor area of 16 acres on a total site of 433 acres, just outside the eastern limit of Edmonton. It is divided into three areas, the petrochemical, the cellulose acetate and the yarn. The yarn area came into production in July, 1953, when filament yarn and staple fibre were made. As chemical processes were begun, one by one and in series, cellulose acetate, pentaerythritol, methanol, acetone, formaldehyde, propylene glycol, n-propyl acetate, acetic acid and isobutanol were turned out, in the order named, by the end of 1953. To this list may be added such products as n-propanol, dipropylene glycol, various alcohols, glycols, aldehydes, oxides and ketones. The plant was the first in Canada to manufacture synthetic methanol, n-propanol, isobutanol, n-propyl acetate and pentaerythritol, and a number of industrial chemicals like methyl isobutyl ketone, butylene glycols, methyl isobutyl carbinol and glycol ethers.

Basically the plant was constructed to produce about 12,500 tons per year of cellulose acetate flake and a number of organic chemicals mentioned above and to manufacture 8,500 tons of pentaerythritol. About 60 per cent of the cellulose acetate flake was to be made into filament yarn and staple fibre of which 90 per cent would be purchased by the parent company, Celanese Corporation of America, which for a considerable time has been the world's largest producer of yarns and fabrics from cellulose acetate. To provide the alpha-cellulose needed to manufacture rayon, the Celanese Corporation completed a pulp mill at Prince Rupert, British Columbia, in 1951. It is operated by a subsidiary corporation, and the parent company contracted to buy up to 200 tons daily for 20 years. With the discovery of oil in Alberta and the development of oil refining and natural-gas processing plants in the Edmonton area, Celanese decided to build a plant at Edmonton to use some of the Prince Rupert cellulose. Thus the Edmonton plant is part of a highly integrated corporate structure which manufactures pulp, industrial chemicals, cellulose compounds and textile yarns and fibres. The cellulose acetate not

made into yarn and fibre in this plant is also purchased by the parent company; the various organic chemical compounds are sold to all comers.

A large part of the funds for the Edmonton plant was raised by bonds whose sale was facilitated by the parent company's assurance of a market for a given output. To secure fuel, a contract was entered into with the Ajax Petroleums Company to supply up to 50 million cubic feet of natural gas daily from adjacent gas fields during the 10-year period 1953-63. Ajax had discovered large amounts of gas but little oil in the course of its exploration program. To realize on its discoveries it agreed to deliver gas at a rate lower than that of any other company in the region. The company set up a subsidiary, the Ajax Alberta Pipeline Company, which built over 50 miles of gas-gathering and transmission lines from the Morinville gas field to Edmonton at a cost of $1.7 million and with a capacity of 85 million cubic feet per day. To obtain the liquefied petroleum gases needed for raw materials, Canadian Chemical entered into contracts with Imperial Oil and McColl-Frontenac to deliver up to the amount of 62,500 gallons per day. Cellulose was to be shipped by rail from the Prince Rupert pulp mill and Celanese Corporation arranged for delivery of up to 8,600 tons per year. A steam plant was constructed, capable of using 7,200 gallons of water per minute from the North Saskatchewan River.

The project was daring and visionary and became the largest industrial plant in Alberta. It was a long-run business proposition, based upon anticipated long-term growth of markets for textiles and chemicals, and not the kind of project which would recover the capital invested and yield an economic return during the early years of operation. The company had its share of initial, short-run difficulties. The textile market slumped in 1954, the first full year of operation, and the parent company experienced difficulties in disposing of contracted output from the plant. There was a variety of technical difficulties in smoothing out and synchronizing the complex chemical processes during the initial period of operation. The Ajax Company ran into financial difficulties because of the relatively low input of gas of the chemical plant and Canadian Chemical and Ajax negotiated an increased price for gas. However, the textile market is recovering, the market for chemicals is growing, and the long-term prospects of the enterprise look bright enough. Output grew rapidly during 1955 and 1956, resolving some of the difficulties encountered at first.

Another major project completed in 1953 in the Edmonton refinery area was the polyethylene plant of Canadian Industries Limited. Polyethylene is a high molecular weight, thermoplastic resin which is formed when ethylene is polymerized at high pressure. It was first developed by Imperial Chemical Industries Limited in England in 1933, and the same company built the first pilot plant in 1937 and the first commercial

plant in the world in 1939. During the war it found many applications for insulation purposes. After the war the number of uses multiplied; it was made into piping for distribution of cold water in private water systems, into houseware, kitchenware, toys and beltings; it was used increasingly to insulate communication cables of nearly every kind, and its use as a packing material, both as film and container, has become widespread. Canadian Industries Limited decided in 1951 to build a plant in Canada to supply the growing Canadian market, and Edmonton instead of Montreal was eventually chosen as the site because of the abundant availability of low-cost hydrocarbon stocks as raw materials.

The plant cost about $15 million by the time extensions were made in 1954. The raw material used to produce ethylene is natural gas from the conservation plant of Imperial Oil at Devon. At full capacity the plant may use 10 million cubic feet per day along with eight million gallons of water and 35,000 kwh of electricity. The gas contains about 75 per cent of methane, 20 per cent of ethane and five per cent of propane. The Canadian Industries plant extracts the ethane, uses some gas as fuel and pipes the rest of it, chiefly methane, into the mains of the local gas utility, Northwestern Utilities Limited.

The process of obtaining ethylene from the ethane is highly complex and involves the use of very heavy precision-made machinery which is very expensive. This means that the capital cost is a very large item in operation expenses. For this reason, too, the plant must be large to secure economies of scale. When the plant was built it was expected that the Canadian market would be sufficiently large to permit operation close to capacity almost from the beginning. There were misgivings about locating in Edmonton because of the great distance to the main market, Eastern Canada. Offsetting distance, however, was the availability of low-cost natural gas and the seeming difficulties of obtaining refinery gases at Montreal or Sarnia because of competition by various firms in the petrochemical and other industries in these centres. The Edmonton plant had initial technical and marketing difficulties; there are many finicky operations to be synchronized at the inception of any chemical plant and it takes time to develop market outlets, especially during a year like 1954 when the Canadian boom levelled off. The initial capacity was 6,000 tons of polyethylene resin per year; this was increased in 1954, and expansion to 20,000 per year is already being considered to meet actual and potential market demand.

Several sulphur plants are now in operation that use "sour" natural gas as raw material. The Shell Oil Company constructed the first in Canada at Jumping Pound. Since the turn of the century most of the sulphur used in North America has come from sulphur domes in Texas and Louisiana; this region, indeed, supplied 80 per cent of the world's

elemental sulphur in the 1940's. The demand for sulphur became so great that critical shortages arose by the 1950's. A process which reduced sulphur dioxide from smelter gas to produce sulphur, utilized by The Consolidated Mining and Smelting Company before the Second World War, fell short of providing adequate quantities. During the Second World War sulphur was produced from the hydrogen sulphide in sour natural gas in Arkansas, and several plants have been built in the United States since then.

Shell had discovered the Jumping Pound gas field in 1944 and began to develop it with the hope that crude oil might also be found. However, it proved to be a large natural gas field and, since there was no market for gas, operations in the field ceased in 1947. By 1950, however, the demand for natural gas in Calgary and southern Alberta towns had risen so much that the gas utility, the Canadian Western Natural Gas Company, had to cast about for additional supplies. The company made an agreement with Shell to construct a 20-mile pipe line to Calgary with a minimum capacity of 50 million cubic feet of gas per day; the oil company agreed to drill additional wells in the field; it also decided to build a gas scrubbing plant and a sulphur plant. The former was completed in 1951 and it removed hydrogen sulphide, carbon dioxide, natural gasoline and water vapour from the gas, making it suitable for use by the utility company. The latter plant was finished in 1952 at a cost of $400,000 and with a capacity of 30 long tons of sulphur per day. The entire output was contracted for years ahead by the Powell River Paper Company in British Columbia to be used in processing pulp. The natural gas consumption of the Calgary utility increased rapidly after 1951 and Shell Oil stepped up its scrubbing facilities in 1954 to supply this market. At the same time, a uranium company, Gunnar Mines Limited of Toronto, began to construct a sulphuric acid plant at Lake Athabasca to provide acid for treating uranium ore. The Shell Oil Company built another sulphur plant during 1954 at a cost of $500,000 with a capacity of 50 tons per day to provide sulphur for the Gunnar Mines Plant. Shipments began in 1955; the sulphur is transported 500 miles by rail to Waterways, Alberta, and is then barged 280 miles northward down the Athabasca River.

As the world price of sulphur rose in 1950 and the United States began to ration exports to various countries, the manufacture of sulphur in Alberta became an economic proposition. Royalite Oil Company accordingly began to construct a sulphur plant at Turner Valley in 1951 which was completed the following year. It cost approximately $500,000 and had a capacity of 30 long tons per day. Much of the natural gas in the Turner Valley field has a high hydrogen sulphide content and is delivered to Royalite by its subsidiary, Madison Natural Gas Company.

A fourth sulphur plant has been completed recently at Pincher Creek by the British American Oil Company. It is expected that the construction of the Trans-Canada pipe line will make the operation feasible economically since processed natural gas, stripped of sulphur, butane and other substances, can then be sold to the Trans-Canada company. More sulphur plants are being planned in Alberta and the problem of marketing sulphur will become of consequence. Competition among

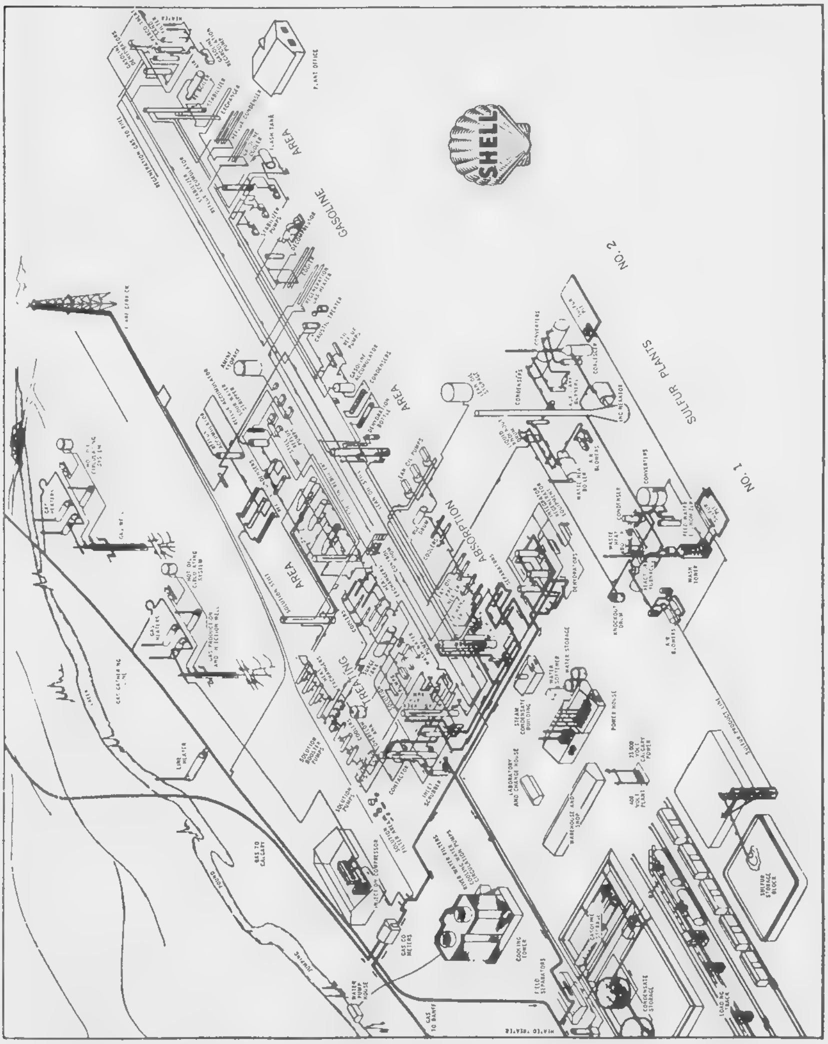


Fig. 48 Jumping Pound gas plant and field.
Courtesy of Shell Oil Co. of Canada

world suppliers has recently become keen and the world consumption of sulphur has not expanded as rapidly as expected since 1955.

The total cumulative investment in petrochemical plants in Alberta grew from less than $10 million in 1946 to more than $150 million by the end of 1956. Table XIX indicates in summary form the petrochemical plants of Alberta.

Table XIX

Petrochemical Plants in Western Canada

Place	Company	Source of Hydrocarbon Raw Materials	Principal Product
Edmonton, Alta.	Canadian Chemical Co. Ltd.	Natural gas and refinery streams	Cellulose acetate, misc. aliphatics
	Canadian Industries Ltd.	Natural gas	Polyethylene
Fort Saskatchewan, Alta.	Sherritt Gordon Mines Ltd.	Natural gas	Ammonia
Calgary, Alta.	Consolidated Mining & Smelting Co.	Natural gas	Ammonia
Southern Alberta	Royalite Oil Co.	Natural gas	Sulphur
	Shell Oil Co. of Canada	Natural gas	Sulphur
	Northwestern Nitrochemicals Ltd.	Natural gas	Ammonia
	British American Oil Co. (formerly Canadian Gulf)	Natural gas	Sulphur
Fort St. John, B.C.	Jefferson Lake Sulphur Co.*	Natural gas	Sulphur

*Under construction.

The petrochemical development in Alberta was an induced effect of the oil discoveries. Most of the investment was concentrated in the Edmonton area and was compressed into the early years of the 1950's after Leduc and Redwater had assured an ample supply of natural gas and oil in the area, and refineries and natural gas plants had been built which

could supply the specific hydrocarbons required. Since then further investment in the Edmonton area has been relatively small. There have, however, been significant plant investments since 1954 at Pincher Creek (sulphur) and Medicine Hat (fertilizer) in southern Alberta. The industry produces a great variety of products, and marketing problems present themselves all too readily in a region as remote from markets as Alberta. The allied matter of markets for Alberta natural gas also has to be settled before many factors affecting petrochemical production become known. What is significant is that Alberta has acquired another important export industry.

The Income Effects

The petrochemical industry induced income growth in Alberta through its investment spending and its operation expenditures during the decade. The expenditures on new investment were made chiefly during the early 1950's.[1] The expenditures on operation did not become substantial until 1953 when the large plants completed in the Edmonton area began operations.

A large part of the new investment in petrochemical plants consisted of imports of heavy and specialized equipment. Specialized contractors and personnel from other regions were employed in considerable degree since the petrochemical industry was so new in Alberta. An estimated 40 per cent of the total expenditure accrued to Alberta residents in the form of wages, salaries, contractors' margins, land costs, supplies and materials. The spending of these receipts generated further income in Alberta. Table XX shows estimates of the contribution of the petrochemical industry to Alberta income.

The contribution of the industry to Alberta income was less than one per cent before 1951. It reached five per cent in 1953 when the construction of plants reached a peak. Currently the industry provides about three per cent of the personal income of the province.

[1]The following indicates estimated new investment in petrochemical plants in Alberta:

In millions of dollars

1947	1	1952	45
1948	0	1953	53
1949	0	1954	5
1950	8	1955	7
1951	13	1956	20

Estimated from ABS and DBS data.

Table XX

The Income Contribution of New Investment In and Operations of the Petrochemical Industry in Alberta, 1947-56

In millions of dollars

	From New Investment[1]	From Operations[2]	Total
1947	1	3	4
1948		3	3
1949		3	3
1950	6	3	9
1951	10	3	13
1952	34	5	39
1953	40	22	62
1954	4	23	27
1955	5	28	33
1956	15	30	45

[1]From estimates of new investment. These were reduced by the import content and then multiplied by the usual ratio.

[2]From estimates of the ABS and DBS.

19

Natural Gas

The Natural Gas Industry in Alberta Before 1947

For decades Alberta has produced nearly nine tenths of Canada's output of natural gas. Total production in 1956 was four times the output of 1946. The 1956 production of 200 billion cubic feet was equivalent to about 35 million barrels of oil, approximately one quarter of the crude oil output of the province during the year. At this rate it would take more than 100 years to exhaust the present estimated reserves in Alberta; it is obvious that the province has an exportable surplus. The 1946 output was equivalent to about eight million barrels of oil, not much more than the crude oil production in that year. The estimated reserves of that year, less than two trillion cubic feet, were sufficient for 30 years at the 1946 rate of production.

Gas was discovered in Alberta in 1883 at Alderson and the first commercial production began in 1904 at Medicine Hat. The drilling required in the Medicine Hat field was very shallow, generally about 1,000 feet, but the field was developed by the City of Medicine Hat only to the extent of local requirements. The main productive formation is termed Medicine Hat sandstone of Upper Cretaceous age. The field has been explored fairly thoroughly in recent years and it is now one of the four fields in Alberta with reserves exceeding one trillion cubic feet. Medicine Hat has operated a natural gas distribution system as a municipally owned utility for more than 50 years; the rates charged have been the lowest in Alberta with industrial concerns obtaining gas at five cents per mcf. The equivalent price of crude oil in terms of thermal units would be about 30 cents per barrel; coal would have to be priced at considerably below $1.00 per ton to compete. Domestic rates are higher but they are low in relation to rates elsewhere. The cost of obtaining gas from the field has been moderate because of the shallow drilling. Consequently, even with

low rates, the city government has obtained a considerable net revenue on its utility operation. This happy state of affairs is on the verge of coming to an end as competing uses in external markets are developing. In 1957 the Alberta Conservation Board authorized the sale of gas to the Saskatchewan Power Corporation from the field by companies which have done development work in it.

In 1909 gas was discovered at Bow Island, between Medicine Hat and Lethbridge. In 1912 a 170-mile, 16-inch pipe line was laid from this field to Calgary. This was the first pipe line of either oil or gas in Western Canada. Short spur lines were built into Lethbridge in 1912 and to several towns during subsequent years. Gas was also discovered at Foremost, 30 miles south of Bow Island, and a 10-inch line was laid in 1912 from this field to the Bow Island gathering station. The fields and the pipe-line system were owned and operated by the Canadian Western Natural Gas, Light, Heat and Power Company (renamed Canadian Western Natural Gas Company some years ago) which distributed gas in Calgary and Lethbridge and in towns along the pipe line from Bow Island. Both the fields had small original reserves and the gas company had difficulties for many years in providing consumers with adequate supplies. These difficulties were met when the Turner Valley field became a gas producer.

The sales of gas by the Canadian Western Company rose rapidly in the late 1930's and during the war years as the population of the centres served increased. The price of coal rose by one fifth in 1939-46 and jumped to more than 50 per cent above the prewar level in 1947. This spelled trouble for the coal industry in the urban centres served by gas. By 1946 the process of conversion to natural gas from coal was virtually completed in domestic and commercial establishments in Calgary, Edmonton and some small urban centres. Industrial users also swung over rapidly to natural gas.

There were several finds of gas in the Edmonton area. The most notable was that in the Viking district, southeast of Edmonton. Northwestern Utilities Limited constructed a double 12¾-inch pipe line to Edmonton in 1923, a distance of 77 miles. The company expanded its business gradually in Edmonton and extended its service to several towns before 1947. Both Canadian Western and Northwestern Utilities are subsidiaries of International Utilities, a holding company with its head office in New York.

In 1927 the Wainwright Gas Company piped gas from Fabyan on the eastern fringe of the Viking-Kinsella field to the town of Wainwright. With the discovery of oil and gas near Vermilion in 1939, Franco Utilities Limited built a five-mile pipe line to serve the town of Vermilion. By 1946 there were nearly 600 miles of gas transmission lines in the prov-

ince of which Canadian Western operated about half and Northwestern almost all the rest. The major cities and about a dozen towns were served; most of the towns and villages of the province still used coal and so did the residents of rural areas. The Viking-Kinsella field was considered to be the largest gas reservoir of the province, a rank which it lost in subsequent years as new fields were found and the greater potential of the Medicine Hat field was established.

During the early 1940's several major gas finds were made in the course of wildcatting for oil. Some notable ones were those at Suffield, Princess, Pendant D'Oreille, Black Butte, Pouce Coupe and Jumping Pound. During 1945-46 Imperial Oil carried on an intensive drilling program which helped to define the limits of the Viking-Kinsella field.

Discoveries and Reserves, 1947-56

Estimating natural gas reserves is an even more tenuous exercise than that of estimating oil reserves. Essentially the same variables are involved—area of the field, thickness of the pay zone, porosity, connate water, permeability, bottom-hole pressures and so forth. However, since markets have been lacking to date, there has been little development work in gas fields to provide adequate reservoir data and to delimit areas. Estimates of the quantities of gas found in oil fields have become fairly firm with the development of the fields.

Few estimates of gas reserves were made before 1947 and these were sketchy and incomplete. In 1947 Dr. George S. Hume, Director of Geological Surveys, Dominion of Canada, made a survey of the reserves in the prairie provinces. Proven reserves were estimated at about 1.4 trillion cubic feet and consisted of reservoirs in the Viking-Kinsella, Turner Valley, Medicine Hat, Foremost, Bow Island, Brooks and Vermilion fields. Another 2.2 trillion cubic feet were classified as probable with Jumping Pound, Princess, Leduc and Pendant D'Oreille accounting for about 90 per cent of this total. The survey also listed many potential fields without attaching estimates.

The Alberta government soon took a hand in the matter because of the pressures exerted upon it to permit the export of gas from the province. In November, 1948, it appointed a Royal Commission (the Dinning Commission) to enquire into the relationship of reserves to potential consumption within the province. The commission held hearings and gathered much information which was published in its report released in the spring of 1949. It did not make any recommendations with respect to the export of gas.

In the meantime, the reserves of Alberta gas were augmented rapidly

by new discoveries. A most notable one was made by the Canadian Gulf Oil Company south of the town of Pincher Creek (see fig. 50). The company had difficulties in drilling and testing the discovery well because the equipment was corroded by the hydrogen sulphide in the gas. The new find proved to be a "wet" gas field, and tests made in early 1948 indicated an initial flow of 12.5 million cubic feet daily along with about 350 barrels of distillate. Drilling was carried to 12,516 feet in Mississippian Rundle.

The Leduc-Woodbend field was found to contain much gas associated with oil as gas caps or in solution. The Redwater field contained much less since it had little gas cap and not much gas in solution. The gas-oil ratio in the Pincher Creek field was close to 40,000 cubic feet per barrel which makes it primarily a gas field. In contrast, the ratio in Leduc was about 600 cubic feet per barrel of oil and in Redwater less than 200 cubic feet. Gas was also found in other oil fields as well as in various locations where it is not associated with oil. In mid-1950 Dr. Hume reported proven reserves of 2.8 trillion cubic feet and probable ones of 4.2 trillion cubic feet for a total of 7.0 trillion cubic feet. This represented an increase of 3.4 trillion cubic feet over the estimated 3.6 trillion cubic feet of 1947, a rate of increase of more than one trillion cubic feet per year.

In July, 1949, the Alberta government followed up the report of the Dinning Commission by authorizing the Conservation Board to receive applications and submissions from companies wishing to export gas. Then began long-drawn-out hearings at which a number of operating companies submitted various reserve estimates to convince the board that Alberta had sufficient gas for export. The whole matter was complicated by the jurisdictions of the two federal governments of Canada and the United States. While the question of permitting the export of gas was a provincial matter, it would become a federal one as soon as gas left Alberta. The federal government, through the Board of Transport Commissioners, exercised jurisdiction over the routes and construction of interprovincial pipe lines. To export gas from Canada, a permit had to be obtained from the Department of Trade and Commerce. To import gas into the United States, the permission of the Federal Power Commission must be sought.

Several companies were formed to export gas from Alberta and their first objective was to persuade Albertans and their government to authorize export. Many Albertans felt that the small communities, and even the farms, should be served before any export took place. This was an uneconomic objective since the population density must be considerable to warrant the cost of transmission lines and distribution pipes. Many Albertans, too, were not sure that there was enough gas to serve existing local markets, and some extremists insisted that a 50-year supply of gas

for provincial use should be assured before any export took place. A number of Albertans felt that industries using large amounts of gas would come to Alberta if export was not permitted.

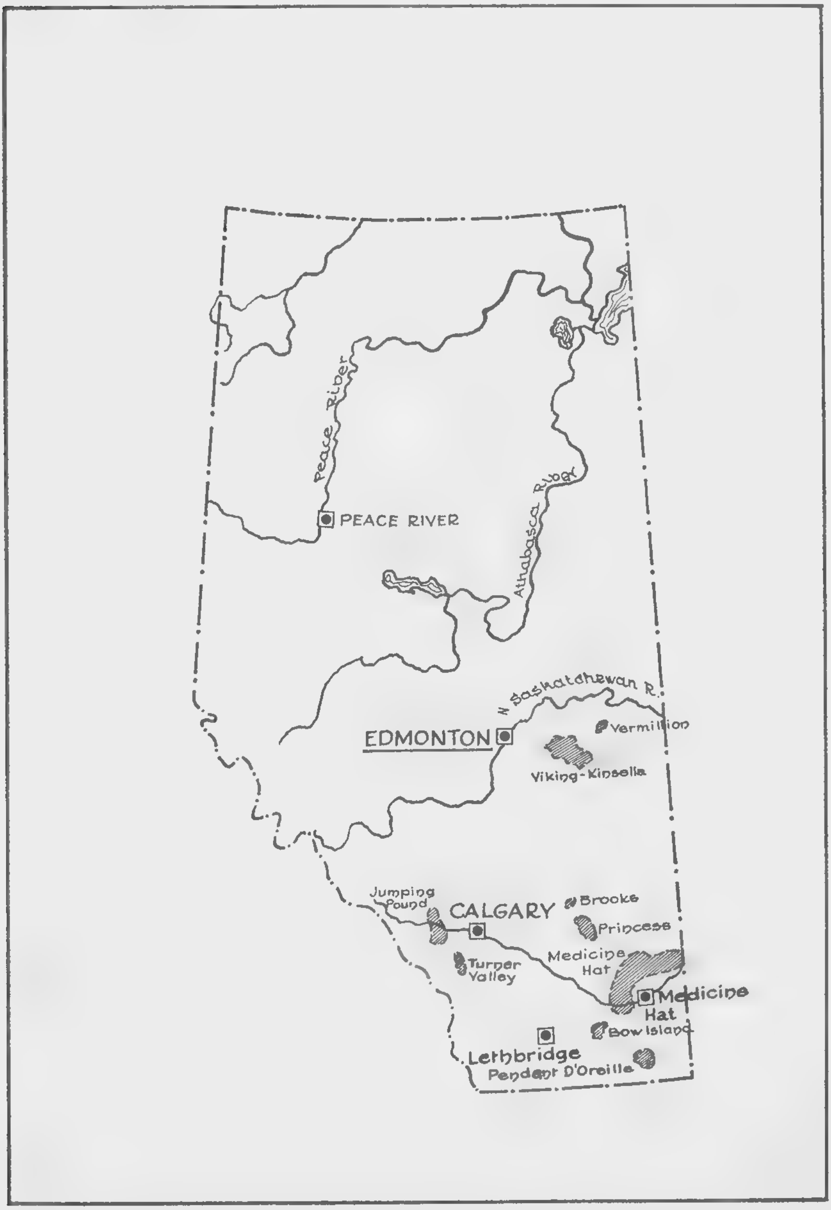


Fig. 49 The main natural gas fields of Alberta in 1946

Company submissions pointed out that if export were permitted, exploration would be stimulated and adequate supplies for both provincial and export markets would be assured. Benefits to the provincial treasury were stressed. It was pointed out that markets would be required before much of the gas could be utilized industrially. For example, it would pay to produce gas in the Pincher Creek field if a market could be found for the processed dry gas after it had been stripped of hydrogen sulphide. The latter could be processed into sulphur. Without export of dry gas the field would lie dormant and there would be no sulphur industry. It was also shown that fuel costs are an important cost element in only a few industries such as those already established at Medicine Hat. The petrochemical industry uses natural gas as a raw material but it uses relatively small amounts.

Albertans remained skeptical about the matter for years and let the Conservation Board proceed in its own cautious way. Three companies applied to the board for permits to export gas to the Pacific coast. One was the Northwest Natural Gas Company, a U.S. corporation with two Canadian subsidiaries, the Alberta Natural Gas Company and the Alberta Natural Gas Grid Company, which hoped to build a grid system to gather gas in Alberta and then pipe it through the Crowsnest Pass to Spokane and Seattle in Washington, to Portland, Oregon, and to Vancouver, British Columbia. Industries such as the smelters at Trail, British Columbia, and an atomic plant at Hanford, Washington, would be served en route. Another company, the Prairie Pipe Lines Company, proposed to follow the same route and to serve the same markets as the Northwest Natural Gas Company. In late 1950 this company became affiliated with the Pacific Northwest Pipeline Corporation of Houston, Texas, which planned to build a gas line of more than 2,000 miles from Texas to the Pacific northwest states. Supplies from Texas would be supplemented by gas transmitted from Alberta by Prairie Pipe Lines. The third company was the Westcoast Transmission Company, an affiliate of Pacific Petroleums. It proposed to construct a gas pipe line through the Yellowhead Pass at Jasper and thence to Vancouver, Seattle and Portland. It changed its plans as large gas finds were made in the Peace River area at Pouce Coupe by the California Standard Company and in the Peace River Block of British Columbia by Pacific Petroleums; the new plans called for a line from the Peace River fields to Vancouver. A point stressed in the submissions of the companies was the vulnerability in wartime of the Pacific northwest states and British Columbia which lacked coal, oil and gas generally.

Two companies applied for permits to export gas eastward. One was Western Pipe Lines, an associate of the Calgary and Edmonton Corporation, which planned to purchase Pincher Creek gas and to transmit it to

serve the urban centres of Saskatchewan and Manitoba and possibly to sell gas from the Manitoba terminus to the Northern Natural Gas Company to serve the Minneapolis-St. Paul market. The other was the Canadian Delhi Company which had large reserves in the large Cessford field and was carrying on an exploration program to increase its reserves.

A sixth company, the Canadian-Montana Gas Company, applied for permission to export gas to serve Montana industries. It was organized by the McColl-Frontenac Oil Company and the Montana Power Company to acquire the Pakowki Lake (Pendant D'Oreille, Etzikom, etc.) gas fields in southeastern Alberta, discovered by McColl-Frontenac and Union Oil of California, and to export gas to Montana. Finally, in December, 1949, the Canadian Western Natural Gas Company and Northwestern Utilities formed an affiliate named Alberta Inter-Field Gas Lines Limited which applied for permission to construct a natural gas gathering system (grid) in Alberta. It would purchase natural gas from producing companies and deliver it as a common carrier to the companies serving the Alberta market and to those exporting gas. Presumably, it would be regulated by the provincial government which might also prorate production among fields and producing wells and set quotas on deliveries to purchasers.

Several reserve estimates were made by the companies in submissions to the board. Billions of cubic feet of gas were tossed about with statistical ease and the estimates varied considerably. The most complete study was that presented to the board by the Canadian Delhi Company which engaged the services of the consulting firm of De Golyer and MacNaughton of Dallas, Texas. The proven reserves were estimated at nearly 8.6 trillion cubic feet as of August 1, 1951. Probable reserves of 2.5 trillion and possible reserves of 2.6 trillion cubic feet were indicated for a grand total of 13.7 trillion cubic feet. Of this amount, the Texas firm deemed 8.4 trillion cubic feet to be marketable.

These figures were far above the first estimates that had been made by the Conservation Board in an interim report published in January, 1951, which set Alberta reserves at 4.66 trillion cubic feet. Even this figure was in excess of the board's estimate of Alberta requirements for the 30-year period 1951-80 which was as follows:

In trillions of cubic feet	
Domestic users	0.87
Commercial users	0.75
Industrial users	1.43
Total consumption, 30 years	3.06

This estimate assumed consumption averaging 100 billion cubic feet per year. In the light of sales of 51 billion cubic feet in 1950, this seemed to be a generous estimate. But considerable gas is flared, returned to formations, or used in the field. In 1950 production was 75 billion cubic feet or 24 billion cubic feet in excess of sales.

The board did not recommend export. It pointed out that the fields serving the Calgary system did not have a 30-year supply and that new fields like Pincher Creek and Cessford would have to be relied upon. The Viking-Kinsella field was not likely to be adequate to meet Edmonton and district requirements for 30 years, and Leduc and Redwater outputs were contingent upon the production of oil. To draw upon small, isolated fields was not economic. The Peace River region had a large surplus, but not enough to justify the construction of a long pipe line to the coast. Gas export had to wait for the proving up of additional reserves.

This took place rapidly and by early 1952 the board estimated established reserves of disposable gas at 6.8 trillion cubic feet. The De Golyer and MacNaughton firm put proven, probable and possible reserves at 16 trillion cubic feet. The board was conservative in keeping with its responsibility; it could not engage in speculative possibilities. The first admission by the board that there might be an exportable surplus came in 1952 when the export of gas to Montana from the almost untapped Pendant D'Oreille and other fields in southeastern Alberta was permitted.

The board also declared the Peace River region a surplus area and in June, 1952, it granted the Westcoast Transmission Company a permit to export natural gas from Alberta fields in the Peace River. The company needed these fields to complement its supply on the British Columbia side of the region. After this, matters moved fast. In 1953 the board decided that there was enough gas to serve Alberta for years plus a surplus outside the Peace River region for export to Eastern Canada. This decision set in motion a tangled web of events which culminated in the construction of the Trans-Canada pipe line in 1956-57. We shall trace the story of the two pipe lines at a later stage.

The board estimated established reserves at 11.5 trillion cubic feet in mid-1953, about 4.7 trillion more than at the end of 1951. Its estimate of Alberta requirements was increased greatly in view of the rapid rise in consumption and production. After allowing for domestic requirements for 30 years and for exports to British Columbia and Montana, the board declared 4.8 trillion cubic feet to be surplus gas available for export. About two thirds of this surplus consisted of the gas in the Pincher Creek and Cessford fields in the southern part of the province. In subsequent years the board made further estimates to keep up with the new discoveries as follows:

In trillions of cubic feet

January 1, 1951	4.7
December 31, 1951	6.8
June 30, 1953	11.5
March 31, 1954	13.4
June 30, 1955	15.6
December 30, 1956	18.3

The increase per year during the last six years has averaged more than two trillion cubic feet and by the end of 1957 the board's estimate will likely exceed 20 trillion cubic feet. Estimates by some consulting reservoir engineers, which take probable and possible reserves into account. run much higher but cannot be considered official. What matters is that all the estimates indicate a great deal of gas and a need for export markets.

The Natural Gas Fields of Alberta

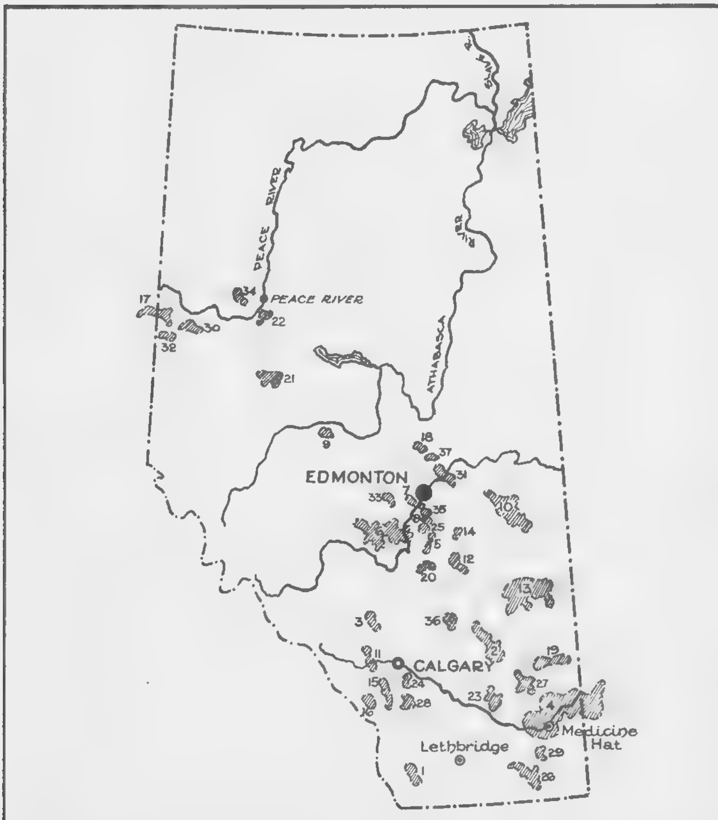
More than 300 natural gas pools and about 150 fields, each with reserves in excess of one billion cubic feet, are scattered widely throughout Alberta.

Southern Alberta has nearly half the reserves. These include the four leading fields of Pincher Creek, Cessford, Harmattan-Elkton and Medicine Hat, each with more than one trillion cubic feet. It has one half-trillion field (Jumping Pound) and ten fields with reserves between 100 and 500 billion cubic feet. Of these 15 major fields, only two, the Harmattan-Elkton and Turner Valley, are also oil fields. There are four notable condensate fields, Pincher Creek, Jumping Pound, Savanna Creek and Okotoks. The rest are fields where the gas is not associated with oil. The main productive zones are of Mississippian, Lower Cretaceous and Upper Cretaceous age. There are also some Jurassic and Devonian zones.

Central Alberta has more than two fifths of the reserves in the province, but no fields in excess of one trillion cubic feet. There are eight fields with reserves above half a trillion. There are eight further fields with more than 100 billion cubic feet. Gas in association with oil in Devonian formations accounts for more than two fifths of the reserves of Central Alberta. Lower Cretaceous fields, mostly with non-associated gas, make up more than a fifth of reserves, and Upper Cretaceous Cardium fields, associated with oil (chiefly Pembina) less than a fifth.

The Peace River region of Alberta has almost one and a half trillion cubic feet of reserves, nearly one tenth of the provincial total. Most of the gas is found non-associated in Lower Cretaceous formations, but there are Devonian formations (e.g. Sturgeon Lake and Sturgeon Lake South)

where gas is found both in associated and non-associated form. There are considerable Triassic reservoirs at Tangent, Whitelaw and Sturgeon Lake South, the first two non-associated with oil. There are also several Permo-Pennsylvanian fields.



(ONLY FIELDS WITH ESTIMATED RESERVES EXCEEDING 100 BILLION BARRELS)

1 PINCHER CREEK	13 PROVOST	26 PENDANT D'OREILLE
2 CESSFORD	14 WESTEROSE SOUTH	27 ATLEE-BUFFALO
3 HARMATTAN-ELKTON	15 TURNER VALLEY	28 OKOTOKS
4 MEDICINE HAT	16 SAVANNA CREEK	29 ETZIKOM
5 HOMEGLEN-RIMBEY	17 POUCE COUPE	30 GORDONDALE
6 PEMBINA	18 WESTLOCK	31 FORT SASKATCHEWAN
7 LEDUC-WOODBEND	19 BINDLOSS	32 POUCE COUPE SOUTH
8 BONNIE GLEN	20 GILBY	33 GOLDEN SPIKE
9 WINDFALL	21 STURGEON LAKE S.	34 WHITELAW
10 VIKING-KINSELLA	22 TANGENT	35 WIZARD LAKE
11 JUMPING POUND	23 PRINCESS	36 HUSSAR
12 NEVIS	24 SARCEE	37 MORINVILLE.
	25 WESTEROSE	

Fig. 50 The main natural gas fields of Alberta in 1956

Table XXI

Major Natural Gas Fields in Alberta, Producing Zones and Reserves, 1947 and 1956

Billions of cubic feet

Name of Field	Producing Zone	Disposable Gas 1947	Disposable Gas 1956	With-drawals to end of 1956	With-drawals in 1956
1. Pincher Creek (G)	Mississippian (Rundle)		1,800	1.1	0.6
2. Cessford (OG)	Lower Cretaceous (Mostly Colorado, but also Blairmore and Viking Zones)		1,070	0.7	0.3
3. Harmattan-Elkton (OG)	Mississippian (mostly gas cap but also solution and non-associated gas)		1,060	1.1	1.1
4. Medicine Hat (G)	Upper Cretaceous (Medicine Hat) but small Lower Cretaceous (Bow Island) and Jurassic (Ellis)	78	1,030	194.5	9.8
5. Homeglen-Rimbey (OG)	Devonian (Leduc Gas cap and solution)		850	2.8	1.5
6. Pembina (OG)	Upper Cretaceous (Cardium solution)		705	33.3	24.4
7. Leduc-Woodbend (OG)	Devonian (mostly Nisku and Leduc gas caps and solution but some Lower Cretaceous)	389[1]	658	96.7	17.0
8. Bonnie Glen (OG)	Devonian (Leduc gas cap and solution)		652	24.3	8.0
9. Windfall (G)	Devonian (Leduc non-associated)		606		
10. Viking-Kinsella (G)	Lower Cretaceous (Viking)	994	579	275.3	21.7
11. Jumping Pound (G)	Mississippian (Rundle)	920[1]	538	68.2	17.1
12. Nevis (OG)	Devonian and some Lower Cretaceous		510	0.1	
13. Provost (G)	Lower Cretaceous (Viking)		510	0.1	

Name of Field	Producing Zone	Disposable Gas 1947	Disposable Gas 1956	Withdrawals to end of 1956	Withdrawals in 1956
14. Westerose South (G)	Devonian (Leduc non-associated)		450		
15. Turner Valley (OG)	Mississippian (Rundle gas cap and solution)	290	355	1,760.3	30.6
16. Savanna Creek (G)	Mississippian (Rundle)		250		
17. Pouce Coupe (G)	Lower Cretaceous (Mainly Cadotte)		210	3.4	0.9
18. Westlock (G)	Lower Cretaceous (Mainly Viking)		202	0.5	0.3
19. Bindloss (G)	Lower Cretaceous (Mainly Viking)		200		
20. Gilby (OG)	Mainly Mississippian (Pekisko) but some Lower Cretaceous		196	0.1	0.1
21. Sturgeon Lake S. and General Area (OG & G)	Devonian (Leduc solution) Lower Cretaceous and Triassic		191	2.4	1.7
22. Tangent (G)	Lower Cretaceous (Gething and Cadotte) and Triassic		170		
23. Princess (OG)	Lower Cretaceous, Mississippian and Devonian	405[1]	168	5.8	
24. Sarcee (G)	Mississippian (Rundle)		160		
25. Westerose (OG)	Devonian (Leduc gas cap and solution)		150	4.8	1.7
26. Pendant D'Oreille (G)	Lower Cretaceous (Bow Island)	260[1]	145	38.1	8.9
27. Atlee-Buffalo	Lower Cretaceous (Viking and Blairmore)		140		
28. Okotoks (G)	Devonian (Wabamun)		135		
29. Etzikom (G)	Lower Cretaceous (Bow Island)		126	0.3	0.3
30. Gordondale (G)	Lower Cretaceous (Cadomin, Cadotte and Gething)		125		
31. Fort Saskatchewan (G)	Lower Cretaceous (Viking)		120	13.8	5.4

Name of Field	Producing Zone	Disposable Gas 1947	1956	With-drawals to end of 1956	With-drawals in 1956
32. Pouce Coupe S. (G)	Cretaceous but some Triassic		115		
33. Golden Spike (OG)	Devonian gas cap and solutions, but some Lower Cretaceous		110	9.3	2.9
34. Whitelaw (G)	Lower Cretaceous (Gething) and Triassic		110	1.0	0.4
35. Wizard Lake (OG)	Devonian solution but some Lower Cretaceous		108	8.4	2.4
36. Hussar (G)	Lower Cretaceous (Colorado and Glanconitic)		105		
37. Morinville (OG)	Lower Cretaceous (Blairmore)		102	14.8	4.4
Totals for 37 fields with reserves exceeding 100 billion cubic feet in 1956		3,336	14,401	2,561.2	161.5
Totals for 151 fields with reserves above one billion cubic feet in 1956 plus all other areas		3,618	18,328	2,754.0	200.2

Source: PNGCB for 1956 and various sources for 1947.

Disposal gas reserves are those remaining after withdrawals. The estimates are net after deducting percentages for reservoir and surface losses involved in production.

[1]These are probable reserves while all other estimated are termed *proved* (1947) or *established* (1956).

(G) Is gas field only.

(OG) Is oil and gas field.

Table XXI sets out some basic information about the 37 fields which had reserves in excess of 100 billion cubic feet in 1956. A striking feature of the data on withdrawals is that in most fields so little has been produced. To the end of 1956 the three old large fields, Medicine Hat, Viking-Kinsella and Turner Valley, have produced four fifths of the gas withdrawn from reservoirs in Alberta and accounted for nearly one third of the Alberta production in 1956. By contrast, the three largest fields of Alberta, Pincher Creek, Cessford and Harmattan-Elkton, have produced only one tenth of one per cent of cumulative Alberta with-

drawals to the end of 1956. The oil-gas fields of Alberta are producing significant quantities of gas along with oil. Much of this gas has to be flared or returned to formations because it is not possible to market it. In some fields, there are conservation plants.

The Composition of Natural Gas

There are wide differences in the composition and heating value of the natural gas found in Alberta pools. The methane (dry gas) content varies from 40 to 99 per cent by weight. Gas with a high methane content is ideal for processing into fuel because relatively little stripping has to be done to remove other hydrocarbons, carbon dioxide, nitrogen and hydrogen sulphide. The first four pools listed in Table XXII are dry-gas pools with a methane content of nine tenths or more. They are also not too versatile, although the high nitrogen content of the dry-gas fields in southeastern Alberta has induced the establishment of a fertilizer plant at Medicine Hat.

Gas that contains significant amounts of carbon dioxide and hydrogen sulphide is usually termed "sour". This applies, for example, to gas at Turner Valley and Jumping Pound where sulphur plants are located.

Several pools listed in Table XXII have gas containing large quantities of ethane, propane, butanes and pentanes which have a high heating value and also provide raw materials for petrochemical plants and refineries (e.g. pentanes in making gasoline). Notable are the Leduc-Woodbend gas cap and solutions, Pembina solution, Redwater solution, and the Erskine and Fenn-Big Valley solutions.

Further development of petrochemical and sulphur plants is contingent upon the opening of markets for dry gas. As a rule, owners of gas wells cannot meet operational costs unless several components can be sold. Consequently, most gas wells in Alberta are capped and the development of known fields has been held back. This state of affairs will change once the two major pipe lines, one from the Peace River region and the other from southern Alberta, are completed.

Production in Alberta

The production of natural gas quadrupled in 1946-56 in response to increasing consumption in Alberta, some exports to British Columbia and Montana, and increasing production of crude oil with its inevitable output of some gas. Natural gasoline output rose from less than a half million barrels to almost one million barrels. Prop-

Table XXII

Components of the Natural Gas in Selected Pools in Alberta

Arranged in descending order of methane content

Pool	Methane	Ethane	Propane	Butanes	Pentanes	Nitrogen	Carbon Dioxide	Hydrogen Sulphide
Medicine Hat	95.7	0.2	0.1	0.1		3.8	0.3	
Pendant D'Oreille	91.7	0.4	0.1			7.6	0.1	
Fort Saskatchewan	91.3	2.2	0.6	0.2	0.4	5.2		
Viking-Kinsella	89.4	1.7	0.8	0.4	7.5			
Jumping Pound	83.9	4.0	1.0	0.7	0.7		6.1	3.6
Leduc-Woodbend, D-3 gas cap	82.4	11.6	4.5			1.5		
Pincher Creek	76.6	3.1	1.3	0.8	0.6	1.4	5.0	11.2
Pembina, Cardium solution	76.1	8.8	8.2	2.8	0.8	2.9	0.3	
Turner Valley, Mississippian solution	72.5	13.0	6.3	2.7	1.0		2.1	2.4
Leduc-Woodbend, D-2 solution	69.9	11.5	5.8	2.2	0.5	4.1	1.1	4.9
Leduc-Woodbend, D-3 solution	66.9	16.8	8.8	2.9	1.0	2.8	0.8	
Redwater, D-3 solution	64.4	14.8	8.1	2.9	0.6	2.5	4.0	2.7
Erskine, D-3 solution	61.0	9.6	5.7	1.9	1.4	4.0	5.2	11.2
Fenn-Big Valley, D-2 solution	49.7	11.0	10.1	4.2	1.3	9.2	11.8	2.7

Source: PNGCB. The data are for the selected well in each pool and there are variations among the wells in each pool. The percentages above are fairly typical of the wells in each pool.

ane, sold mainly to Alberta industries, small towns and farmers, rose from nothing in 1948 to almost one million barrels in 1956. Butane, marketed chiefly to Alberta refineries and petrochemical plants, increased from nothing in 1949 to more than half a million barrels in 1956. Finally, Alberta became a significant producer of elemental sulphur after 1951; nearly all of this output is exported. The 1956 output was more than half of one per cent of world production. The following table summarizes the outputs of the five products for the decade.

Year	Natural Gas billions of cubic feet	Natural Gasoline millions of barrels	Propane millions of barrels	Butane millions of barrels	Sulphur thousands of short tons
1946	50.6	0.4			
1947	53.4	0.4			
1948	61.0	0.5			
1949	67.1	0.5	0.1		
1950	75.6	0.4	0.1		
1951	85.4	0.5	0.2	0.1	
1952	95.6	0.6	0.3	0.1	8.9
1953	114.2	0.6	0.4	0.2	18.3
1954	135.5	0.7	0.5	0.2	22.3
1955	168.8	0.9	0.8	0.5	29.1
1956	200.2	0.9	0.9	0.6	33.5

Source: PNGCB.

Nearly all the natural gas produced during the decade was used in Alberta. The amounts returned to formations, consumed in the field or flared, increased significantly, largely because of the rising crude oil production. The following table shows the disposition of the natural gas produced in 1946-56:

Year	Sales in Alberta	Exports[1]	Other[2]	Total Production
1946	30.4		20.2	50.6
1947	34.0		19.4	53.4
1948	39.6		21.4	61.0
1949	42.3		24.8	67.1
1950	51.5		24.1	75.6
1951	57.7	0.3	27.4	85.4
1952	55.9	8.5	31.2	95.6
1953	63.7	10.0	40.5	114.2
1954	80.9	7.6	47.1	135.6
1955	96.4	12.1	60.3	168.8
1956	104.0	11.7	84.6	200.3

Source: PNGCB.

[1]To British Columbia and Montana.

[2]Returned to formation, plant fuel, processing and shrinkage, line fuel loss, field use and "waste".

Production was much below potential capacity during the decade. The development of new fields has been discouraged because of lack of markets, and in many of them only one or two wells have been drilled and then capped. In 1947 there were 114 capped gas wells in the province; by the end of 1956 the number rose to 712. When export market outlets are provided, many of these capped wells will become producers and additional ones will be drilled in various areas. In the process, much more will be learned about the magnitude of Alberta's gas reserves.

20

Gas Pipe Lines

As in the case of oil, the pipe line presented itself as the logical means of transporting gas from Alberta to distant markets. The construction of gas lines, however, has taken considerable time to decide upon and to execute for a variety of reasons.

The Westcoast Transmission Line

The Westcoast Transmission Company had to wait three years for an export permit from the Alberta Conservation Board. It granted the company a permit to draw upon gas in the Alberta portion of the Peace River region. The Canadian Board of Transport Commissioners granted a permit for the construction of a line from the Peace River to Vancouver. However, economic considerations did not justify a movement of gas to Vancouver unless additional markets were found. So Westcoast Transmission incorporated an American subsidiary in Delaware, Westcoast Transmission Inc., which applied to the U.S. Federal Power Commission for a permit to import gas into the United States from Canada.

Following hearings which began in June, 1952, and ended in June, 1954, the FPC refused to grant Westcoast Transmission Inc. an import permit. Instead, the Pacific Northwest Pipeline Corporation of Houston, Texas, was permitted to construct a line from the San Juan Basin in New Mexico and Colorado to the Pacific Northwest states. The application of Westcoast Transmission Inc. was turned down because the FPC was dubious about having a part of the United States supplied from a region in which it had no jurisdiction over production and transportation.

The decision meant that the construction of a line to Vancouver had to be delayed for an indefinite period. At the same time, it was very questionable if there were enough reserves in the San Juan Basin to supply both a growing California market and a new one in Oregon and Wash-

ington. The two companies began to negotiate with each other, for if they could come to an agreement, Peace River and San Juan Basin supplies could be combined, California could be served adequately and the Oregon, Washington and Vancouver markets could be opened up. A final agreement was reached in December, 1954, among the Westcoast Transmission Company, the Pacific Northwest Pipeline Corporation and El Paso Natural Gas Company.

Under this agreement, Westcoast Transmission was to construct a 650-mile line from the Peace River area to Vancouver and the International Boundary. Pacific Northwest was to construct a 1,400-mile line from the San Juan Basin to Spokane, Seattle, Portland and to the Westcoast terminus on the border. El Paso, the company which was transmitting gas from the San Juan Basin to California, contracted for additional supplies from Pacific Northwest wells in what is called the Four Corners field. The agreement set up a distribution system with great regional appeal and flexibility. Under it the whole Pacific coast market (except Alaska) could be served; Peace River gas could go to California, if necessary; San Juan Basin gas could go to Vancouver, if necessary. Furthermore, an idle resource, Peace River gas, became useful and valuable. The agreement was approved by the Government of Alberta and by the Board of Transport Commissioners, and after the usual hearings, it was approved by the Federal Power Commission in November, 1955.

After six years, then, Westcoast Transmission could begin to construct its line. It takes a long time to initiate the construction of major gas pipe lines, for there are diverse economic interests to be reconciled, both industrial and regional. The existing fuel suppliers in an area fear the intrusion of a new, large energy source with the convenience and efficiency of natural gas. The provision of natural gas in an area furnishes the raw materials and fuel for chemical industries, threatening the markets not only of local chemical plants but of "foreign" ones importing their products into the area. Similarly, Albertans feared for several years that the export of natural gas would retard industrial development in the province. Gas pipe-line and distribution companies compete with each other to serve given areas. When interests conflict in this way, or seem to do so, governments take a hand to arbitrate, to reconcile and to make the best of an almost inevitable economic change by protecting vested interests in some degree, and by encouraging or discouraging potential interests according to their criteria of what constitutes the "public interest".

Westcoast Transmission completed a 30-inch pipe line 650 miles long in August, 1957, running from just inside Alberta to Vancouver, and a 38-mile, 26-inch line from there to Huntingdon on the international border. The official deadline was November 1 of the same year. The

initial capacity is 400 million cubic feet per day with four compressor stations, but it is expected that this can be stepped up to 660 million cubic feet with the installation of five more stations. A gathering system of 155 miles within Alberta and British Columbia and an absorption plant at Taylor Flats in the latter province are under construction.

The cost of the initial line was estimated at $153 million, and this sum was raised in Canada and the United States without government assistance. An additional $20 million had to be raised for the processing plant at Taylor Flats which will extract sulphur, natural gasoline, butane, propane and diesel fuel from the gas and deliver the residue, chiefly methane, into the line.

The B.C. Electric Company will purchase gas from Westcoast Transmission to serve the Vancouver and Lower Fraser Valley area. The Inland Natural Gas Company, incorporated in 1952, will purchase gas to serve interior British Columbia and the whole Peace River region through a number of subsidiaries. Finally, Pacific Northwest will purchase gas for resale in the United States.

The Trans-Canada Pipe Line

The projected pipe line to the east met with even more resistance than that to the west. Two companies, Western Pipe Lines and Trans-Canada Pipe Lines sought authority to transport gas eastward. The former had a limited plan confined to serving Saskatchewan and Manitoba directly and Minnesota through sales to the Northern Natural Gas Company. The Trans-Canada company planned to serve Eastern Canada. It was obvious that duplication would be uneconomic. The Alberta government had previously urged the two companies to merge, and once the Alberta Conservation Board declared surplus gas available for eastern export, the companies did merge under the name of Trans-Canada Pipe Lines. In early 1954 the Government of Canada authorized the company to transport gas from Alberta to Eastern Canada provided the line followed an all-Canadian route, and it also permitted export to Minnesota.

The choice of an all-Canadian route through northern Ontario, which is so largely uninhabited, was questionable on economic grounds. Many people pointed out that the market potential of a line through the United States, roughly parallel to the Interprovincial pipe line, was much greater than in northern Ontario. Proponents of the all-Canadian route argued that the substantial mineral and pulp-and-paper industries of northern Ontario would provide a considerable market, that natural gas would facilitate the development of the region, and that gas could be laid down

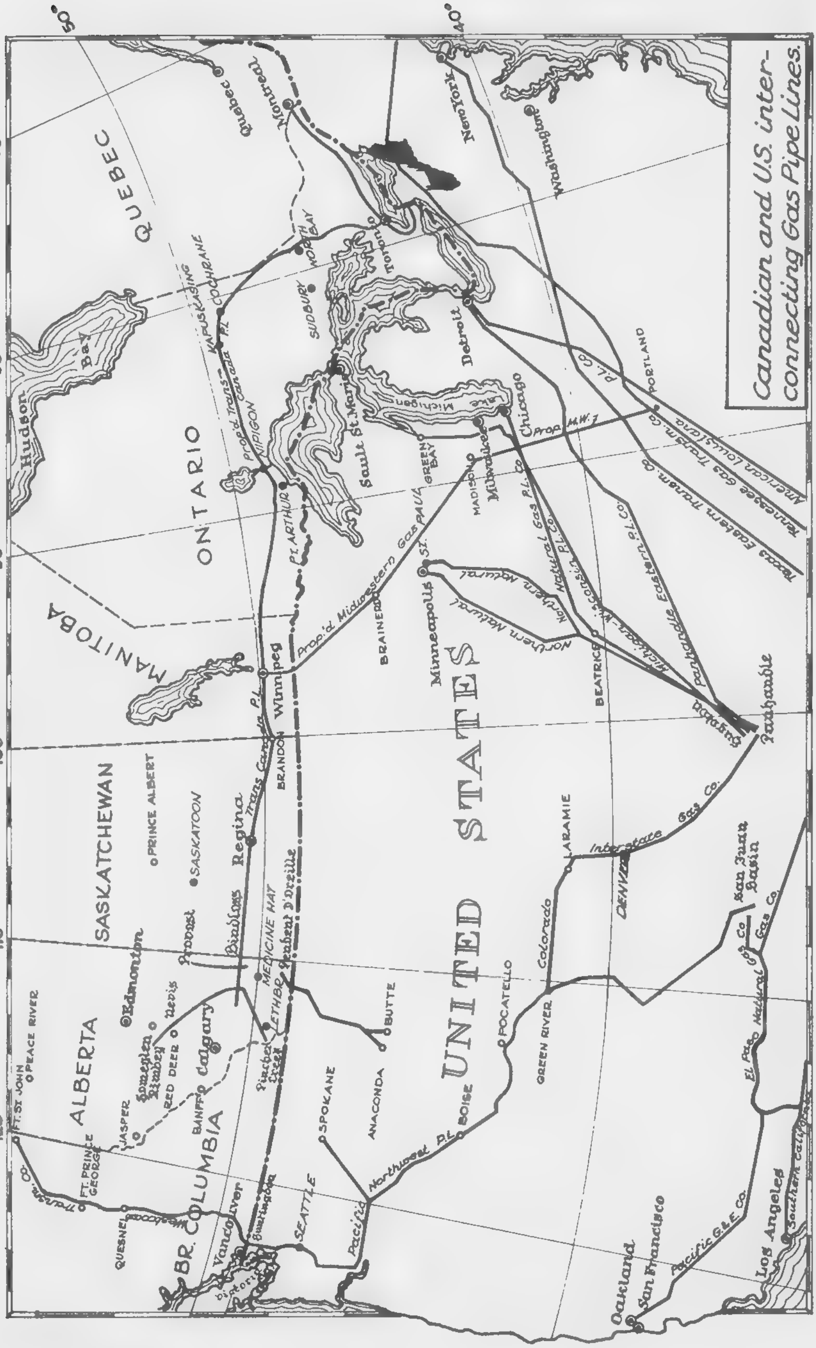

Canadian and U.S. inter-
connecting Gas Pipe Lines.
QUEBEC
ONTARIO
MANITOBA
SASKATCHEWAN
ALBERTA
BR. COLUMBIA
UNITED STATES
Hudson Bay
Quebec
Montreal
New York
Washington
Toronto
North Bay
Sudbury
Cochrane
Kapuskasing
Nipigon
Sault St. Marie
Detroit
Chicago
Milwaukee
Green Bay
Madison
Portland
Lake Michigan
Pt. Arthur
Prop'd. Trans Canada P.L.
Prop'd. Midwestern Gas
St. Paul
Minneapolis
Brainerd
Northern Natural
Beatrice
Panhandle Eastern P.L. Co.
Panhandle
Texas Eastern Transm. Co.
Tennessee Gas Transm. Co.
American Louisiana
Winnipeg
Brandon
Trans Canada P.L.
Regina
Prince Albert
Saskatoon
Edmonton
Red Deer
Calgary
Banff
Jasper
Peace River
Ft. St. John
Ft. Prince George
Quesnel
Westcoast
Vancouver
Victoria
Seattle
Spokane
Anaconda
Butte
Medicine Hat
Lethbridge
Boise
Pocatello
Green River
Northwest P.L.
Pacific
Colorado
Laramie
Denver
Interstate Gas Co.
San Juan Basin
El Paso Natural Gas Co.
Pacific G. & E. Co.
Oakland
San Francisco
Los Angeles
Southern California
50°
40°
70°
80°
90°
100°
110°
120°

Fig. 51

in Toronto and Montreal at a price competitive with coal and oil even with the higher cost via northern Ontario. The Government of Canada stayed with its original decision, but it jeopardized the ability of the company to raise funds in the capital market.

A temporary complication was the decision of the Consumers' Gas Company of Toronto to try to obtain gas from the United States. The Federal Power Commission approved exports from the United States for this purpose in 1953. The Government of Canada suggested that the Toronto company plan to take gas at a comparable price from the Trans-Canada company once its line reached Toronto. In the meantime the Consumers' Gas Company could begin to develop a market for natural gas among Torontonians with whatever supplies it could obtain from the United States.

The Trans-Canada company received a permit formally in May, 1954, to export gas from Alberta. The Alberta Conservation Board authorized the company to export 4.35 trillion cubic feet over a period of 27 years at a daily rate not exceeding 620 million cubic feet. In July, 1954, the Board of Transport Commissioners approved the construction of the line through all-Canadian territory. A line from Winnipeg to Emerson, Manitoba, on the International Boundary, was to be built to deliver gas to the Tennessee Gas Transmission Company which contracted to take 200 million cubic feet of gas to begin with and a further 200 million as enough gas became available. At the same time, Trans-Canada agreed to purchase 90 million cubic feet per day from Tennessee Transmission at Niagara, Ontario, the terminus of one of its lines. This gas was to be sold to the Consumers' Gas Company and the Union Gas Company of Canada to build up the Ontario market. The Winnipeg and Central Gas Company was incorporated to purchase gas from Trans-Canada for distribution in Winnipeg and other Manitoba centres. The Great Northern Gas Company, which already served many Ontario and Alberta communities, was given a franchise to supply Brandon. The Trans-Canada company also made agreements with gas-producing companies for the delivery of gas to the western end of the line. Principals of Trans-Canada also began negotiations with Quebec Hydro, a provincial government body, to purchase its Montreal gas utility system.

There were now two main obstacles. One was to find enough money to build the line and the other was the Federal Power Commission. In a way, both of these obstacles were intertwined. Without a market of any kind in the United States, financial institutions hesitated to provide the company with funds. Many protests were filed with the Federal Power Commission by United States fuel interests against imports by Tennessee Transmission. The most immediate opposition came from the Northern Natural Gas Company and several other gas distribution com-

panies serving Minnesota and related areas, such as the Peoples Gas, Light and Coke Company and its subsidiaries of Chicago, and the Michigan-Wisconsin Pipe Line Company of Detroit, a subsidiary of the American Natural Gas Company. Hearings before the Federal Power Commission were necessary to straighten out this tangle. They were begun in 1956 and have not yet been completed, and no decision has been made up to the present.

To raise funds, Trans-Canada approached the Government of Canada in early 1955 and requested a guarantee of annual interest and sinking fund charges on first mortgage bonds for $275 million, almost 80 per cent of the estimated $350 million required to construct the line. In the meantime, the Alberta government extended the company's license to export gas and the Board of Transport Commissioners renewed the permit of the company to construct the line. While negotiations for funds were going on, Tennessee Gas Transmission suggested to the Canadian government that the line be built southward from Winnipeg into the United States to deliver 500 million cubic feet of gas per day at Emerson plus additional quantities for transmission by Tennessee to Eastern Canada. The government refused permission to carry out this plan. In August, 1955, Trans-Canada and Tennessee reached an agreement whereby Trans-Canada would sell 200 million cubic feet per day to Tennessee at Emerson, and Tennessee would furnish Trans-Canada with up to 87 million cubic feet per day from the United States to enable Trans-Canada to build up a market in Ontario and Quebec, pending construction of the main line from the west.

At this point the governments of Canada and Ontario brought another factor into the picture; they suggested the establishment of a Crown corporation to construct a 675-mile pipe line from the Manitoba border to Kapuskasing in Ontario with the federal government supplying two thirds of the estimated $118 million required and the Ontario government the other one third. The Crown company was to be leased and operated by Trans-Canada for a maximum period of 25 years, and Trans-Canada was to buy the line as soon as it was in a financial position to do so. An agreement was signed accordingly in November, 1955, between the federal government and Trans-Canada. The Northern Ontario Pipe Line Crown Corporation was formed on June 7, 1956, after a long and controversial debate in parliament. The corporation immediately lent Trans-Canada $80 million to start work on the prairie section of the gas line.

In June, 1956, then, after more than two years of delay, Trans-Canada began work on a 34-inch line from the Alberta-Saskatchewan border to Winnipeg. Work was no sooner begun than a steel strike in the United States gave rise to a shortage of pipe, delaying construction. Otherwise completion to Winnipeg by the end of 1956 would have been possible.

In August, 1957, gas began to flow eastward. Completion of the line to the Great Lakes is expected in 1958. The Crown company is constructing its line to Kapuskasing; this line is also expected to be finished in 1958. In the same year Trans-Canada will complete the system to Toronto and Montreal. Trans-Canada has negotiated several gas sales contracts in Northern Ontario and the Toronto-Montreal region, pending completion of its line. The Trans-Canada pipe line is a project of major dimensions, and when completed it will be the longest natural gas pipe line in the world, approximately 2,300 miles. It will be another economic link between Eastern and Western Canada. Trans-Canada completed its financing arrangements in February, 1957, by the sale of mortgage bonds, debentures and common stock, and through the Crown corporation the company repaid the indebtedness incurred in June, 1956, at the same time.

The question of gas exports to the Middle Western States remains to be settled. The Federal Power Commission began hearings on May 14, 1957. The Northern Natural Gas, Peoples and Michigan-Wisconsin companies are opposing the application of Tennessee Transmission's affiliate, Mid-Western, to purchase gas from Trans-Canada for distribution in the Middle Western States. At present, the three companies and their subsidiaries, affiliates and associates serving these states have insufficient supplies for the growing market and can be expected to give serious consideration to the import of Alberta gas which can be provided in the Middle West at lower rates than Texas gas.

It is now nine years since the east and west pipe-line projects from Alberta were conceived. Some of the original sponsors are no longer in the picture but the two lines have taken tangible form. Canada will presently have an integrated natural gas pipe-line system; no longer will Alberta be the main consumer of an important regional resource. Integration with natural gas systems in the United States is a reality on the Pacific coast, and it appears to be only a matter of time before reciprocal flows of gas will materialize in the central and eastern market areas.

Such integration has unassessed economic implications in both countries. It will be less explicitly a joint venture in the defense of North America than the DEW line project, but it could do more to promote the kind of unity which North America requires. This may seem paradoxical in view of the disputes and rivalries which have characterized the natural gas projects to date. But natural gas has a way of winning friends and influencing people, once it gets a chance to demonstrate its uses. The quantity of gas which will be marketed in both Canada and the United States from fields in both countries can be expected to rise sharply for a number of years to come, and to such a level that natural gas may become the major fuel for space-heating in the two countries.

The Alberta Gas Trunk Line Company

One more gas pipe-line system requires mention. This is the gathering system planned within Alberta. The Alberta Interfield Gas Lines Company, sponsored by the two major gas companies of Alberta and their parent company, International Utilities, was not given a permit to operate by the Alberta government. Instead the government sponsored a new company, the Alberta Gas Trunk Line Company, and incorporated it by a special act on April 8, 1954. Its function is to gather and transmit gas within the province to domestic companies and to exporters like Trans-Canada. Lines are now under construction and the western terminus of Trans-Canada at Bindloss was opened officially on July 23, 1957. The lines projected initially will carry gas from the Pincher Creek, Cessford, Nevis, Homeglen-Rimbey and Provost fields and total 547 miles in length with a capacity of delivering 620 million cubic feet per day to Trans-Canada at Bindloss.

Upon incorporation in 1954, two kinds of common stock, Classes A and B, were authorized for the Alberta Trunk Line. A total of 2,002 Class B shares with voting privileges were authorized, of which 925 were issued at a par value of $5.00 to the utility companies of Alberta, the gas export companies, to gas producers and processors, and to directors appointed by the Government of Alberta. Non-voting Class A shares authorized number 8,000,000 of which 147,680 were issued at a par value of $5.00 to the Class B interests mentioned above. Another 2,552,320 Class A shares were sold in March, 1957, at a price of $5.25. This issue was restricted to bona fide residents of Alberta and was over-subscribed by cash orders exceeding many times the issue price of the shares. Brokers and banks had to resort to a system of allotting the stock to applicants. The shares have since risen markedly in price on the market. The proceeds from common stock totalled about $13½ million. The Government of Alberta has undertaken to purchase $36½ million of first mortgage bonds at a rate of 5½ per cent to provide the rest of the money for the first stage of construction.

The company will be a common carrier of gas and may also purchase and sell gas. During the initial four years of operation it will carry gas to the Trans-Canada terminus at Bindloss, charging a tariff of four cents per mcf, payable by Trans-Canada. After that the rates will be determined by the cost of service. This includes maintenance and labour costs, local taxes, income taxes, depreciation allowances and a 7½ per cent return on a depreciated rate base as established by the Alberta Board of Public Utilities Commissioners.

Once the great pipe lines to the east and west come into full operation, Alberta's gas, like its oil, will be more than a potential resource. Annual production may reach one trillion cubic feet or five times the 1956 output by the early 1960's. New gas fields will be sought; fields already discovered will be developed; the value of prospective acreage will rise. New petrochemical plants can be expected to be constructed to utilize the various components of natural gas which will be left behind after the removal of "dry" gas for export. This development, however, cannot be achieved overnight for many things must be learned about the markets for petrochemical products and about the technical aspects of the natural gas in various fields before plants can be located on an economic basis. Furthermore, the prospects of the export gas lines have to be translated into some years of actual experience to provide reasonably firm data on outputs, costs and prices. All qualifications aside, natural gas promises to provide Alberta with another dynamic decade.

21

The Economic Development of Alberta

The Alberta economy experienced rapid growth as the petroleum industry developed. Between 1946 and 1956, the population rose by two fifths, personal income more than doubled, the net value of production tripled and bank clearings quadrupled.

The structure of the economy also changed greatly. Between 1946 and 1956, the contribution of mining (chiefly petroleum) to the net value of production rose from 10 to 26 per cent. That of construction, which includes many petroleum industry activities, increased from 14 to 26 per cent. The contribution of manufacturing was 18 per cent in both years, indicating a rate of development in this sphere which kept pace with the growth of the whole economy. Finally, the contribution of agriculture fell from 54 to 27 per cent.

The Great Rise in Investment

A striking feature of the economic development of Alberta during the decade was the great rise in new investment. Such expenditure rose more than sixfold in 1946-56, fed by the direct outlays of the petroleum industry and by outlays induced by the oil development. Table XXIII shows the estimated capital expenditures on new investment during the decade.

The estimates in the table are based on a definition of investment, used mainly for national income accounting purposes, which excludes certain capital expenditures of the petroleum industry. These exclusions are

expenditures on land acquisition, a large part of those on surveys and exploratory drilling. As oil companies acquire land and explore it, there is no immediate production of goods and services. Consequently, for the purpose of estimating the gross national product of Canada, the expenditures are deemed unproductive.

As far as Alberta is concerned the expenditures on land, surveys and dry-hole drilling constituted a flow of capital into the region. They had important effects upon the incomes of Alberta residents which we have already noted and they did much to induce population and production increases in the region. Therefore, they cannot be ignored in making estimates of the importance of the petroleum industry in the province. That industry, too, regards expenditures on land and exploration as part of the cost of producing oil.

The expenditures of drilling and developing producing wells are included in Table XXIII under the category "mining". In fact, these make up almost all the expenditures under "mining" since new investment in coal and other mining was small. If the expenditures on land and exploration were included, the new investment in "mining" becomes greatly enlarged. For example, in 1956 the estimated new investment in "mining" was nearly $400 million instead of the estimated $187 million shown in the table. Accordingly, too, the total new investment in Alberta was about $1,100 million instead of the $909 million shown in Table XXIII.

The estimates made in previous chapters of investment in refineries, natural gas plants and petrochemical plants are included in their entirety under "manufacturing" in Table XXIII. Pipe line investment is included under "utilities" and investment in marketing facilities under "trade, finance and commercial".

Much of the investment, exclusive of the direct expenditures of the petroleum industry, was induced by its rapid development. For example, many new manufacturing plants were constructed to serve the growing regional market. Rising capital expenditures on housing and utilities were required as the urban population increased by large increments. The capital expenditures of institutions and government departments rose very markedly to provide facilities for both urban and rural areas. Much of the capital expenditure of the government departments was financed by receipts from petroleum land rights.

Total new investment per capita in Alberta has consistently run above the total Canadian new investment per capita since 1946. The differential has been increasing markedly. In 1946 the Alberta per capita average was 10 per cent above the Canadian and presumably, without the subsequent oil development, the Alberta average would have been fairly close to the Canadian. Instead, the Alberta per capita average rose to 50 per cent above the Canadian by 1951 and in 1956 it was almost

Table XXIII

Capital Expenditures (New Investment) in Alberta, 1946-56

In millions of dollars

Year	Agriculture[1]	Mining[2]	Construction Industry[3]	Manufacturing[4]	Housing	Utilities[5]	Trade, Finance and Commercial	Institutions and Government Departments	Total All Sectors
1946	36	10	4	5	30	10	12	15	122
1947	55	16	5	10	40	20	15	30	191
1948	59	42	6	16	54	30	21	57	285
1949	78	45	6	18	75	40	21	70	353
1950	89	59	8	29	72	47	27	80	411
1951	95	88	9	37	62	51	44	99	486
1952	109	97	10	75	73	75	44	119	602
1953	106	109	8	91	107	83	60	166	729
1954	67	95	20	49	118	95	49	134	627
1955	71	146	30	61	121	95	50	163	735
1956	87	187	42	114	134	126	41	179	909
Total	852	894	148	505	886	672	384	1,112	5,450

Source: Government of Canada, Department of Trade and Commerce. The data for 1946-50 are not official because complete data were not available and the writer made some adjustments in the data at hand.

[1]Includes very small amounts invested in the fishing industry.

[2]Includes mining, quarrying and oil wells. Oil wells account for more than 95 per cent of the totals. Most survey expenditures, dry hole drilling expenditures and acreage acquisition expenditures are not included under the definition of new investment in oil wells employed by the source of the statistics.

[3]Includes investment in forestry as well as in the construction industry.

[4]Includes investment in refineries, natural gas plants, petrochemical plants as well as all other manufacturing plants.

[5]Includes investment in central electric stations and gas works, telephones, municipal waterworks, electric railways, steam railways, water transport, motor carriers, grain elevators, broadcasting, air transport, warehousing and pipe lines.

75 per cent higher. During most of the 1950's the Alberta average exceeded that of any other province. The oil development was the great contributing and motivating factor driving capital expenditure in Alberta upward.

Let us assume that without the oil development which took place, the population of Alberta would have remained constant at 800,000 during 1946-51 and then would have declined by 5,000 annually during 1952-56. Suppose that in such an event the new investment per capita in Alberta would have been 10 per cent above the Canadian average in each year instead of the much higher levels experienced with the oil development of the decade. Fig. 52 shows graphically the difference between new investment in Alberta under the conditions set out and under the actual

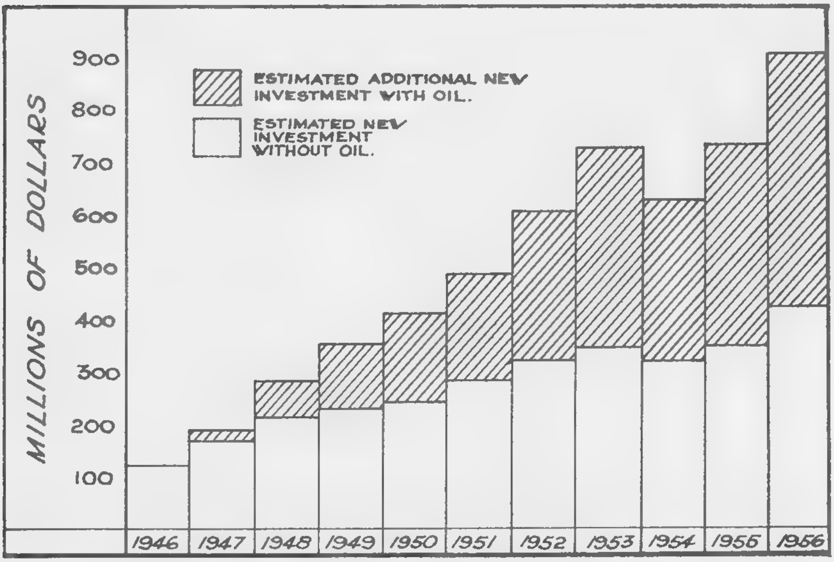


Fig. 52 Estimated new investment in Alberta in 1946-56 (millions of dollars)

conditions with oil development. For example, in 1956 the probable total investment in the absence of oil development would have been an estimated $420 million. Instead, it was an estimated $909 million, a difference of nearly $500 million accounted for by oil development. This does not take into account the expenditures on land and exploration; when these are included the difference rises to about $700 million.

Table XXIV summarizes the total new investment by the petroleum industry at this point. This summary serves to bring together the esti-

mates made in previous chapters and to relate them to total new investment in all sectors of the Alberta economy.

Table XXIV

New Investment by the Petroleum Industry in Alberta, 1947-56

In millions of dollars

Year	Land Acquisition[1]	Exploration and Overhead[2]	Development[3]	Total Investment in Production[4]	Other Investment[5]	Total Investment
1947	5	10	8	23	5	28
1948	12	21	25	58	10	68
1949	32	39	53	124	18	142
1950	57	48	50	155	56	211
1951	44	68	64	176	31	207
1952	57	82	80	219	71	290
1953	57	79	68	204	81	285
1954	104	79	84	267	49	316
1955	100	82	140	322	59	381
1956	120	84	187	391	78	469
Total for Decade	588	592	759	1,939	458	2,397

Sources: Estimates were made from data obtained from ABS, DBS and industry sources.

[1]Payments to governments, corporations and individual freeholders.

[2]Administrative overhead, surveys and dry-hole drilling.

[3]Development drilling and other development costs.

[4]Total for the categories under 1, 2 and 3.

[5]Transportation, refining, natural gas plants, petroleum marketing facilities and petrochemical plants.

The total new investment by the industry during the decade was nearly $2.4 billion. Out of this, an estimated $1,939 million was spent on "production". This is more than one billion dollars in excess of the $894 million shown as the total for "mining" in the estimates in Table XXIII which are based on national income accounting concepts.

The Rise of Income from Petroleum

We can now summarize the contribution of the petroleum industry to the personal income of Alberta. This contribution came from the new investment of the industry and from its spending on operations insofar as the expenditures were financed by non-residents. Table XXV brings together the estimates of income generated by the various activities of the petroleum industry which were shown in the previous chapters.

Table XXV

Estimated Income Generated in Alberta by the Petroleum Industry from Non-Resident Funds, 1947-56

In millions of dollars

Year	From Investment in Production	From Other Investment	Total from Investment	From Operations	Total Income Generated
1947	17	5	22	9	31
1948	56	9	65	20	85
1949	115	16	131	25	156
1950	146	44	190	36	226
1951	174	25	199	51	250
1952	199	53	252	66	318
1953	191	59	250	91	341
1954	279	38	317	106	423
1955	315	45	360	137	497
1956	385	59	444	168	612
Total for Decade	1,877	353	2,230	709	2,939

Nearly three billion dollars of personal income was generated in Alberta by the expenditures of the petroleum industry during the decade, an average of approximately $300 million per year. The income rose progressively in every year to attain a level in 1956 which was 20 times that of 1947. This achievement gave the petroleum industry major status in the provincial economy by the end of the decade.

But we have not yet assessed the full contribution of the industry. Some of the new investment in Alberta in economic ventures outside the petroleum industry would not have been undertaken if there had been little oil development. One example is the pulp mill constructed at Hinton, west of Edmonton, during 1955-56. The proving up of substantial natural gas reserves in the province, the availability of local sulphur and the potential growth of Western Canada were factors taken into consideration in locating the plant in Alberta, which also happens to have the requisite forest potential. Nearly all the funds required for construction were obtained outside Alberta. There are a number of other examples of manufacturing plants and of commercial and residential buildings which were constructed in Alberta as a result of the oil development and which were financed largely by non-resident funds. Furthermore, some municipal governments borrowed some funds from outside Alberta, particularly during the early years of the decade 1947-56, to construct public buildings, other structures and utility facilities.

Estimates of the income generated by these induced activities, financed by non-resident funds, need to be added to the totals set out in Table XXV. This is done in Table XXVI which relates the petroleum-industry contribution to the total personal income of the province during the decade.

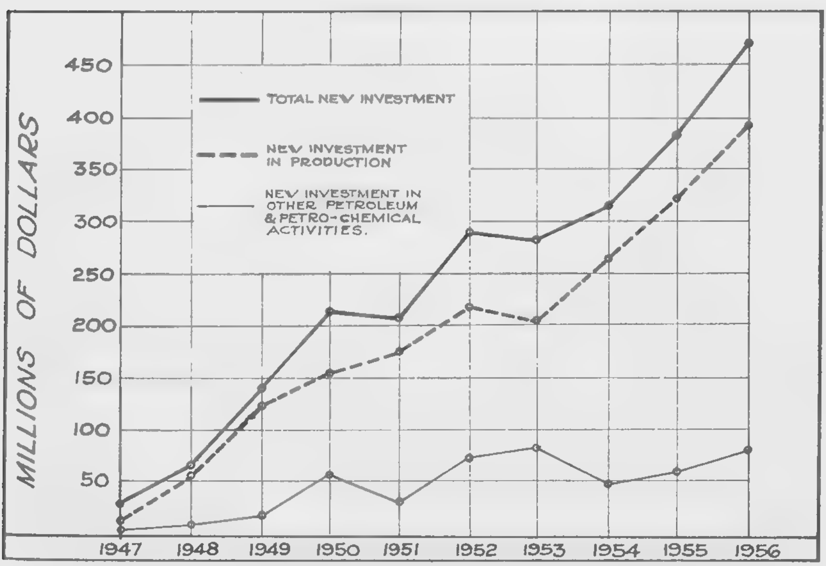


Fig. 53 New investment in the petroleum industry in Alberta, 1947-56 (millions of dollars)

The New Alberta Economy

During the decades preceding 1946 agriculture in all its phases generated from four fifths to nine tenths of the personal income of Alberta. This contribution was generated mainly from the proceeds received from the export of both primary and processed agricultural products with investment in agriculture by non-residents playing a minor role. Essentially Alberta was a one-industry economy within which the alternate opportunities of labour and capital were quite restricted. It was a vulnerable economy, experiencing many income fluctuations because of the instability of agriculture.

During the war years of the 1940's the governments of Canada and the United States contributed to the income of the Alberta economy through relatively heavy expenditure on defense. During the immediate postwar years the Government of Canada made a net contribution to Alberta incomes.

The petroleum industry changed the structure of the economy fundamentally. It also increased its size and dimensions. The extent of the change during the decade 1947-56 can be gauged by applying the same analysis as that used for the petroleum industry to other activities in the Alberta economy which earned or received funds from non-residents. However, no detail is set out here with respect to data and methods used in making estimates.[1]

Like the petroleum industry, the agricultural industry is complex and variegated in nature. It includes not only the primary activities of farmers but also a wide variety of processing, transportation, storage and marketing activities. In Alberta about half the output of the farming sector is exported; there have been considerable variations in the ratio annually, depending chiefly upon weather and demand conditions. There are substantial exports by meat-packing plants, dairies, flour mills and sugar refineries. In 1946 these plants exported more than 60 per cent of their output; this percentage fell during the decade, and in 1956 about half of the output that year was exported. As Alberta's population and income grew because of the rise of the petroleum industry, an increasing domestic market for agricultural products developed.

Farming prospered until 1951. After that year the price of farm products fell almost continuously until 1956. At the same time the costs of operations continued to rise. The difficulties experienced in marketing

[1] Agriculture and other industries were examined in detail by the author. A technical treatise or article would be required to cover methods and analysis.

Table XXVI

Estimated Income Contributions of the Petroleum, Agricultural and Other Industries in Alberta, 1947-56

In millions of dollars

Year	Petroleum Industry[1]	Agriculture Primary[2]	Agriculture Associated Activities[3]	Total	Residual Activities[4]	Total Personal Income[5]
1947	35	385	170	555	119	709
1948	90	445	210	655	125	870
1949	170	435	180	615	111	896
1950	240	370	175	545	136	921
1951	265	540	180	720	194	1,179
1952	350	560	210	770	133	1,253
1953	370	445	210	655	253	1,278
1954	470	355	210	565	180	1,215
1955	560	370	210	580	182	1,322
1956	690	425	210	635	214	1,539

[1]The cash income generated by the petroleum industry as estimated in Table XXV plus an allowance for "induced" activities.

[2]The estimated personal income contributed by the farming industry. Cash income was included with the generative ratio suggested in Chapter 12 being applied. Income in kind and changes in farm inventories were included without applying the generative ratio used to obtain estimates of income created by non-resident cash flows.

[3]The estimated cash income contributed by the export portion of a variety of activities. These include railway and truck transportation, storage (elevator and other), processing (meat-packing, dairy processing, flour-milling and sugar refining), agricultural wholesaling and other marketing activities.

[4]This includes estimated cash income contributed by non-resident funds provided by investment in and exports of the coal industry, northern development, furs, fish, forestry, the non-metallic products industry, the tourist industry and miscellaneous activities. Income generated by investment stimulated by petroleum industry development and financed by non-resident funds has been included under the petroleum industry. The residual category also includes income generated by investment financed by non-resident funds in non-export industries, not induced by the petroleum industry, and income generated by the federal government insofar as it provided a net cash inflow into Alberta through its revenue-expenditure policy.

[5]DBS, *National Accounts, Income and Expenditures.* Personal income includes wages, salaries, supplementary labour income, military pay and allowances, investment income, net income of farmers from farm operations, net income of other unincorporated enterprises and government transfer payments.

wheat aggravated matters further. Without the oil development the Alberta economy would have suffered a recession during 1953-56. It did not only prevent such an event but also provided economic growth.

The income contributions of the agricultural industry are shown in Table XXVI together with those of other industries or activities earning or receiving non-resident funds. The contribution of the primary agricultural industry (farming) takes income in kind and changes in farm inventories into account. This contribution fluctuated annually, with the greatest income flow being provided in 1952 and the lowest in 1954.

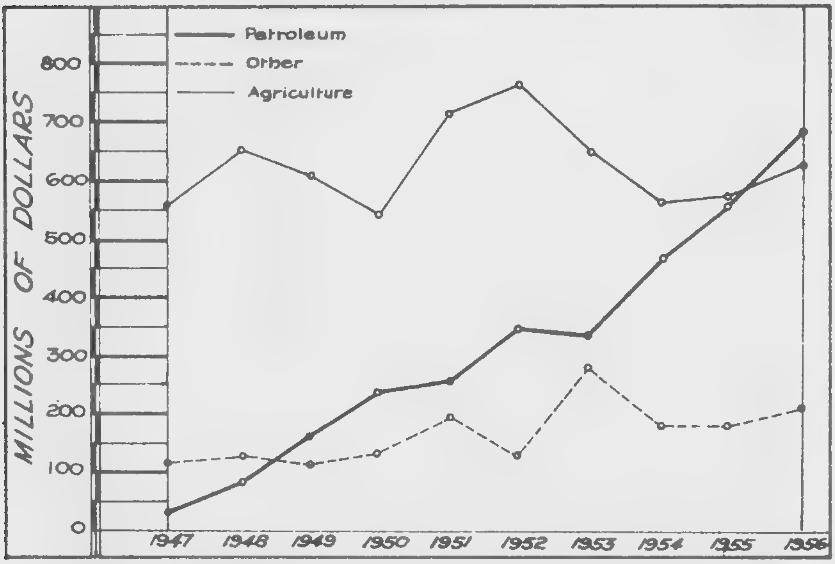


Fig. 54 Estimated personal income generated in Alberta by the petroleum, agricultural and other industries, 1947-56

There was no upward trend. The income contributions of associated activities, meat packing, flour-milling, dairy processing, sugar refining, agricultural transport and storage, and agricultural wholesaling and other marketing did not fluctuate very much throughout the decade nor did they rise in any appreciable degree above the 1947 level. Unlike the income contributions of farming, those of activities associated with farming included cash flows only. This is also the case for the petroleum industry and for residual industries; only in the case of farming are income in kind and changes in inventories taken into account.

There remains a "residual" category. It includes a miscellany of activities which draw cash inflows of funds into Alberta—the coal industry,

the tourist industry, northern development, the fishing and trapping industries, forestry and non-metallic products industry. It also includes any net contribution to income made by the federal government. Finally, it includes miscellaneous new investments in any activities not mentioned here which were financed by non-resident funds and which were not induced by the petroleum industry.

Table XXVII

The Estimated Percentage of Personal Income Generated in Alberta by the Petroleum, Agricultural and Other Industries in Alberta, 1947-56

Per cent of total personal income

Year	Petroleum Industry	AGRICULTURE Primary	Associated	Total	Residual Activities	Total
1947	5	54	24	78	17	100
1948	10	51	24	75	15	100
1949	19	49	20	69	12	100
1950	26	40	19	59	15	100
1951	23	46	15	61	16	100
1952	28	44	17	61	11	100
1953	29	35	16	51	20	100
1954	39	29	17	46	15	100
1955	42	28	16	44	14	100
1956	45	27	14	41	14	100

Source: Table XXIII.

Figure 54 portrays the changes in the income contributions of three categories during the decade.

The agricultural contribution was clearly dominant until 1954 when the rapidly rising contribution of the petroleum industry approached the agricultural. By 1956 the petroleum industry contribution to income exceeded it. What has emerged in Alberta is a dual economy with the petroleum and agricultural industries furnishing roughly equal shares of more than two fifths each of the personal income of the province. In the decade to come the petroleum industry promises to hold and even increase its present lead over agriculture in view of prospective increases in expenditures on exploration, land and development, and with the potential rise of operating expenditures as markets for crude oil, natural gas and petrochemicals grow. On the other hand, the long-term outlook for agriculture cannot be viewed unfavourably, especially as the export demand for

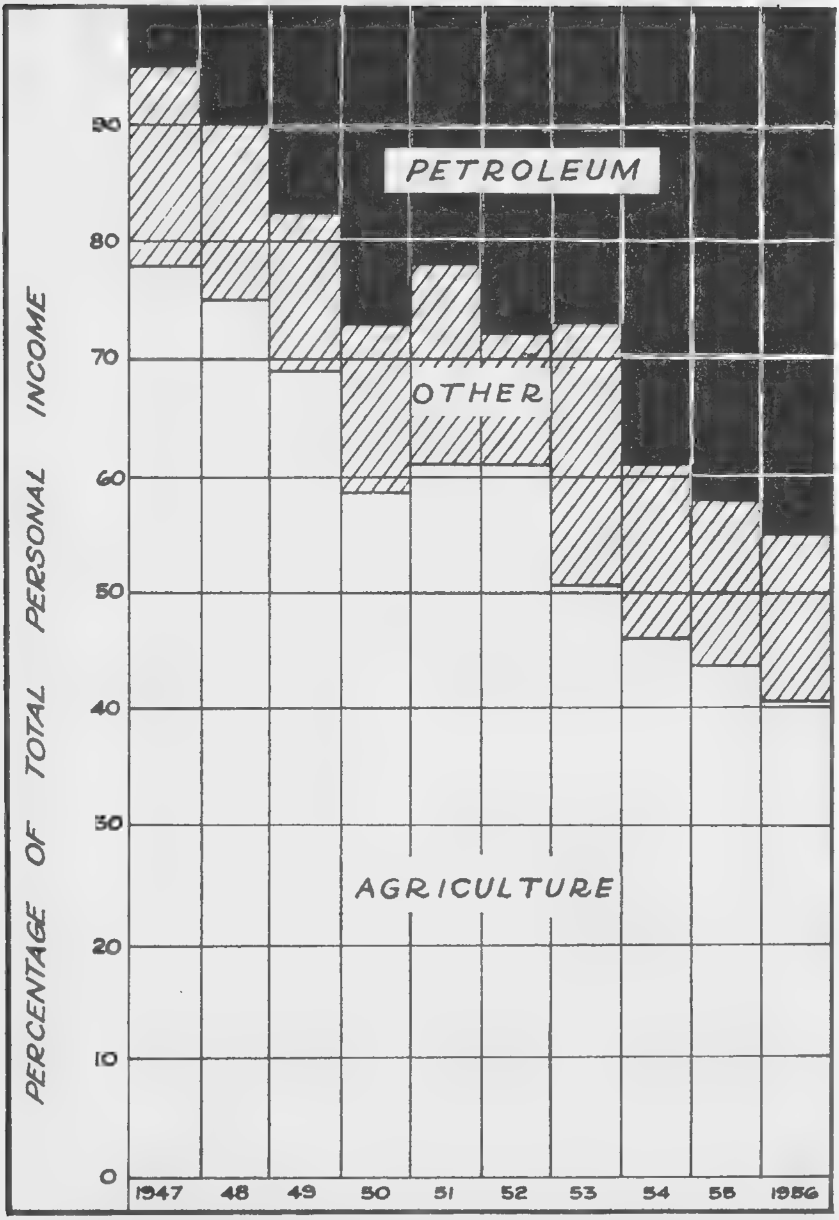


Fig. 55 The estimated percentage of personal income generated in Alberta by the petroleum, agricultural and other industries, 1947-56

meats and other animal products increases. What Alberta has obtained through the development of the petroleum industry is an added sector which should provide greater stability and further growth of the Alberta economy in the future. It has become a partner of the agricultural industry, strengthening the latter as well as the Alberta economy generally.

Table XXVII shows the major changes that have taken place by reference to the percentage of personal income that was generated in each year by the three categories of activities shown in Table XXIII. Fig. 55 portrays the changes graphically.

The rise of the petroleum industry contribution is very marked, increasing from an estimated five per cent to an estimated 26 per cent in 1947-50. There was a halt in the rise during 1951-53 between the first flush of Leduc and Redwater and the stimulus provided by Pembina. During 1954-56 the petroleum industry contribution increased rapidly and with an estimated 45 per cent in 1956 it exceeded the agricultural income contribution.

The contribution of primary agriculture fell from an estimated 54 per cent to an estimated 27 per cent in 1947-56 and that of associated agricultural activities decreased from an estimated 24 per cent to 14 per cent. In all, the agricultural industry declined from an estimated 78 per cent to 41 per cent in 1947-56. Currently, then, the fortunes of the Alberta economy are dependent upon two great industries instead of one.

22

Where the Money Came from

The large increases in the regional income contributed by the petroleum industry during 1947-56 were made possible by the heavy inflow of funds from outside Alberta. The residents of Alberta could not have financed the development of their petroleum resources, and without funds drawn from non-residents little would have been accomplished. The savings of Albertans would have been much lower in the absence of the rising income generated by the flow of funds from outside the province.

Alberta underwent rapid economic development half a century ago because it presented a comparative cost advantage in producing agricultural products for export. A few other activities such as coal mining, trapping and fishing provided some opportunities for export sales. A little petroleum was also exported.

The receipts of the agricultural sector from the export of products provided "basic" income for Alberta. When these receipts from outside the province were spent on consumer goods and on capital goods by the agricultural sector, they generated income in other sectors of the economy which served mainly the regional market. If agriculture prospered, capital would also flow into Alberta to be invested not only in agriculture, but also in other sectors. This income would generate income in all sectors. The capital inflow, however, was attributable to the development of agriculture which was responsible for securing the bulk of the income of the region through its exports. Before 1947, then, the Alberta economy expanded or contracted with the fluctuations in the value of agricultural exports and in capital inflows which were influenced chiefly by economic conditions in the agricultural sector.

During the last decade, Alberta has acquired another major export industry. Like agriculture, it is based on the physical resources of the province. Fundamentally, Alberta's greatest asset is land, agricultural

and mineral, and it is the development of the resources of this land which provides exportable products that can be used to pay for imports, to expand the size of the economy and to bring about changes in its structure. Alberta had a large sedimentary basin which presented a challenge to the petroleum industry. The rewards to the searcher for oil were potentially great because the demand for oil was rising throughout the world. More particularly, Western Canada was a deficit area which presented an immediate market for any oil that might be found regionally. The result was a great inflow of capital into Alberta and a great rise in crude oil exports which induced rapid economic growth in the province. Large sums of money were provided by non-residents which increased the "basic" income receipts of Albertans and, in turn, generated further income within the province.

The Sources of the Funds

The money for expenditures by the petroleum industry in Alberta on new investment and producing operations came from a variety of sources. Some companies had considerable holdings of liquid assets on hand before 1947. These were liquidated rapidly and spent in Alberta. Many companies sold securities, chiefly outside Alberta, and some sold fixed assets and interests in other companies located in various parts of the world. The chartered banks played an important part in providing funds which were derived from savers throughout Canada. Depreciation and depletion allowances became of growing significance as the oil development proceeded and as crude oil exports rose. The sale of crude oil provided funds for producing operations, and companies that made profits ploughed them back into exploration and development.

Most of these funds came from outside Alberta. It is doubtful if Albertans provided even five per cent of the capital funds, considering that the province had only about seven per cent of Canada's population during the decade and less than one per cent of the population of North America. By their purchases of crude oil and products Albertans contributed funds for oil in a greater degree. During 1947 provincial residents bought most of the crude oil produced; after that date the fraction of output consumed fell rapidly and during the 1950's about four fifths of the output was exported. Little of the petroleum chemical output was purchased locally; nearly all of it was exported, providing non-resident funds for the province. All told, an estimated nine tenths of the new investment and producing expenditures of the petroleum industry during the decade was provided by non-residents. It was the injection of all this non-resident

spending which accounted for the large increase in the size of the Alberta economy in 1947-56.

The discovery of Leduc gave such a spur to exploration and drilling that revenues from crude oil and gas sales soon proved entirely inadequate. Funds had to be obtained from abroad by the sale of stocks, bonds and subsidiaries.

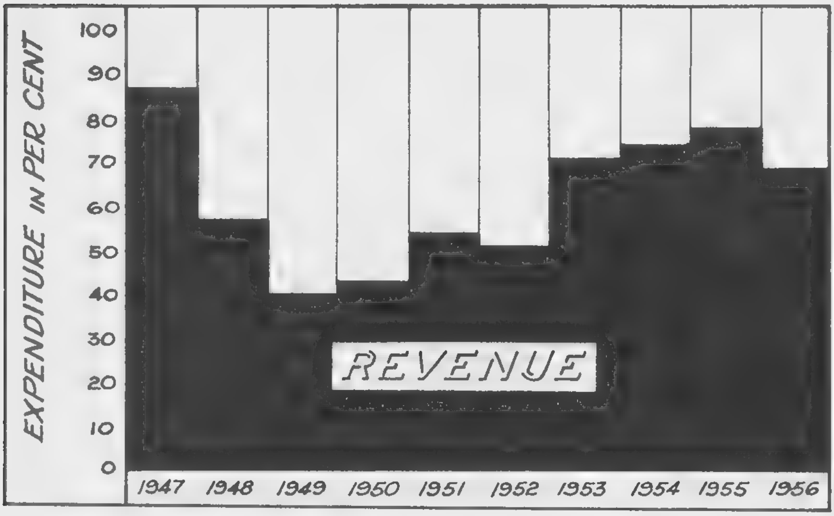


Fig. 56 Revenue from the production of petroleum as a percentage of expenditure on production by the petroleum industry in Alberta, 1947-56

During these years new oil companies were formed almost weekly, selling their speculative shares to the public in Canada and the United States. If these companies found oil during the initial stages of their operations, they survived; if not, they were liquidated or they merged with others.

Illustrative of the demand for funds for exploration and development is the case of Imperial Oil. This company undertook a heavy program of exploration and development. Its cash outlays rose much more rapidly than its cash revenues after Leduc and even more so after Redwater. The rising cash revenues from its hundreds of Alberta oil wells proved to fall far short of its cash expenditure requirements.

At the end of the war the company had $30 million in cash which was soon swallowed up by the holes being drilled in Alberta. In 1948 the company sold its controlling interest in the International Petroleum Com-

pany by offering the shares of the subsidiary to its stockholders and raised $80 million in this way. It was promptly spent on land, exploration and development in Alberta. In February, 1949, the company sold its time-honoured Alberta subsidiary, Royalite and its subsidiaries, to a Montreal group for nearly $15 million. On November 16 of the same year, two Turner Valley subsidiaries, the Foothills Oil and Gas Company and Lowery Petroleums, were sold along with miscellaneous interests for $5 million. Another $5 million was realized in 1949 from the sale of oil and gas interests in the Viking-Kinsella gas field. In 1951 about $80 million was realized from the sale of new shares; its funded debt rose from nothing at the end of 1946 to almost $60 million at the end of 1949 and currently it is in the neighbourhood of $100 million. It is expensive to develop petroleum resources, and the postwar inflation increased the dollar costs.

The deficiency of revenue in relation to expenditure is typical of the initial stage in an intensive search for oil in a given area. In Alberta this deficiency was very marked during the decade 1947-56. The following table illustrates the situation for the ten years and fig. 56 portrays it graphically:

In millions of dollars

Year	Expenditure[1]	Revenue[2]	Revenue as Per Cent of Expenditure
1947	26	22	87
1948	66	38	58
1949	134	54	40
1950	171	74	43
1951	196	106	54
1952	245	126	51
1953	230	162	70
1954	300	226	75
1955	370	289	78
1956	456	320	70
Total for Decade	2,194	1,417	65

[1]Expenditure includes new investment in petroleum production (administration, surveys, dry hole drilling, land acquisition, development drilling, other development costs) plus estimated total producing costs. Royalty distributions are excluded.

[2]Revenue includes estimated receipts from the sale of crude oil and natural gas, net of royalties.

The deficiency can hardly be expected to disappear in the next few years. For this to happen the markets for Alberta crude oil would have to expand greatly or expenditures would have to fall drastically. Growing natural gas sales will, of course, help to reduce the deficiency considerably during the next few years. What matters is that the industry continues to see prospects of recouping its expenditures and the search for oil in Alberta will be continued. What matters, too, is that the funds continue to be provided mainly by non-Albertans in the form of capital inflows or through exports of crude oil and natural gas from Alberta. It is these funds which have built up the Alberta economy to its present dimensions and which will provide for further growth in the future.

During recent years revenues have risen relatively to expenditures. This is shown in the table above and in fig. 56. It is also reflected in a growing number of financial statements of companies. Until 1955 it was chiefly the integrated companies that paid any dividends and income taxes. It was possible for them to do this because they had earnings from transportation, refining and marketing activities. Most of the independent producing companies have begun to earn returns on their investments, but it will be a matter of time before they begin to pay both income taxes and dividends on any great scale. As long as the western Canadian oil and gas potential remains great, most companies with revenues exceeding expenditures will tend to plough them back by investing in additional exploration and development activities. No oil company can stop looking for oil and rest on its laurels of discoveries; to do so leads to decline and eventual liquidation.

The Growth of Oil Companies

Obvious features of the development of the petroleum industry during the decade were the increases in the number of companies and their assets. In 1956 there were more than 1,200 firms more or less active in the petroleum industry in Western Canada and of these more than 1,000 had operations in Alberta. Of the total, about half or nearly 600 firms, were oil and gas producers, explorers, developers, royalty companies or merely holders of acreage. About 300 firms provided services and supplies for the industry. There were about 60 drilling contractors, nearly sixty geological, geophysical and engineering consulting firms, about 40 geophysical contractors, nearly 20 petroleum and natural gas operators, several distributors of natural gas, and a dozen firms with refineries. About 60 firms served as financial and investment consultants and as lease brokers. There were half a dozen large firms utilizing petroleum and natural gas as raw materials in producing a

variety of chemical and textile products as well as a number of small ones. In addition, there were several hundred bulk dealers and more than 2,600 retail outlets for gasoline and other petroleum products. The following table is indicative of the increase in the number of companies during the decade:

	About Jan. 1 1947	About Jan. 1 1956
Major integrated (active in exploration and development)	11	23
Major independent (active in exploration and development)	4	25
Minor (with production and some with exploratory activity	53[1]	270[2]
Minor (with land holdings only)[3]	53	87
Total (excluding sundry royalty companies)	101	405

[1]Of these 11 were active in exploration and 42 were straight producers, mainly from wells in Turner Valley.
[2]Excludes land holding and royalty companies.
[3]Companies which held acreage and had no production.

Sources: Financial Post, *Survey of Oils*, annual periodical, and C. O. Nickle and A. R. Smith, *Canadian Oil and Gas Directory*, another annual periodical.

The number of Canadian companies with operations in Alberta increased fourfold during the decade and their total assets rose from less than half a billion dollars to more than two billion dollars. Imperial Oil continued to be the most integrated and largest company with about one third of the total assets of all Canadian companies. In 1956 it accounted for almost a third of the Canadian crude oil output and more than a third of all crude oil processed in refineries and of all product sales. The British American Oil Company continued to run second. In 1956 it acquired the Canadian Gulf Oil Company; this brought its assets up to almost 400 million dollars, about half of the Imperial total. It also made the company more integrated and balanced than it was before since the considerable crude oil reserves and production of Gulf came under its jurisdiction. The Gulf merger also increased its natural gas reserves from about 400 billion cubic feet to nearly 4,000 billion cubic feet, about one fifth of Alberta reserves; a large part of these reserves are in the Pincher Creek field pioneered by Gulf. The McColl-Frontenac Company now has considerable interests in acreage and in crude oil and natural gas reserves

and production, and its American associate, Texaco Exploration, has large holdings in Bonnie Glen and other fields. The three large Canadian companies of 1946, then, continued to be large, accounting for almost three fifths of the total assets of all Canadian companies in 1956.

The next ranking companies are Canadian Oil Companies, which had become integrated by acquiring Anglo-Canadian, and Royalite, both of which had assets of between 50 and 100 million dollars at the end of 1956. Following these, with assets between 10 and 50 million dollars are Hudson's Bay Oil and Gas, Home Oil, Canadian Superior Oil of California, Husky, Triad, Pacific Petroleums, Bailey-Selburn, Canada Southern, Anglo-American Exploration, Calvan Consolidated, Great Plains, Western Leaseholds and Dome Exploration. About half of these companies were formed after 1946.

In addition to companies incorporated in Canada, including subsidiaries of American companies, there are about 40 American companies with branch offices or direct operations in Alberta. We have had occasion to mention a number of them previously. Several of these companies have interests throughout most of the oil-producing regions of the world and have assets running into billions of dollars each. Notable ones are Shell, Texaco (Texas Company), Socony Mobil, Standard Oil of California, and the Pan-American Petroleum Corporation (previously Stanolind), but most of the others are also large. The petroleum industry in Alberta and Western Canada is mainly an extension of the American. Only the United States could provide the large volume of funds, equipment and know-how required to support the continuous, large-scale exploration and drilling program in the western Canadian sedimentary basin during the initial stage represented by the decade 1947-56.

Most of the companies operating in Alberta and Western Canada are small landholding and producing companies. A large number have assets below one million dollars and, indeed, a majority have assets below $100,000. A great number of them are having financial difficulties, but they continue to exist on the basis of ownership or part ownership in one, two or more producing wells and on the hopes that the acreage held will be valuable some day. After 1951 when the first surge of the boom was spent, a process of consolidation and merging began and there are fewer companies today than in 1952. The process is still going on and has been given impetus by the prospect of natural gas exports which is giving value to various acreage holdings of both large and small companies.

The mortality rate of the industry is high and nearly 2,000 companies once active in Canada, mainly Alberta, are dead or dormant. Of the Canadian companies still active in Alberta, only six were incorporated before 1920. They are Imperial Oil (Dominion incorporation, 1880), Canadian Oil Companies (Ontario, 1908), British American Oil Com-

pany (Ontario, 1906; Dominion, 1909), Turner Valley Oil Company (Alberta, 1914), Alberta Pacific Consolidated Oils (Alberta, 1914) and United Oils (Dominion, 1918). Only about one quarter of all Canadian companies were incorporated before 1947; the rest are products of the post-Leduc era.

23

The Income Benefits of Oil

Estimates of personal income in Alberta for 1947-56 were set out in the previous chapters and so were the contributions to it of the petroleum, agricultural and other industries. We shall now use this information to compare what actually happened to personal income in Alberta with what might have been "without oil".

The Changes in the Level and Stability of Income in Alberta

In 1946 the petroleum industry was responsible for less than two per cent of the personal income generated in Alberta. Within four years the industry was generating in excess of one quarter of that income and currently it is responsible for more than two fifths. To obtain perspective on what the income levels and fluctuations would have been if there had been no oil development, the petroleum industry contribution may be deducted from the total actual personal income in each year. This is done in Table XXVIII.

The data in the table are portrayed graphically in fig. 57. It shows the alternative situations of "oil" and "no oil" in better fashion than the table. The striking feature is the impressive growth of income with oil and the lack of definite upward trend without oil. With oil there was only one downturn in income, that of 1954; without oil there would seemingly have been four, those of 1949, 1950, 1952 and 1954. The economy

of Alberta would have been relatively depressed in 1954-56. Without the large federal expenditures on defense projects, the level of income in 1951 would have been lower.

The petroleum industry buoyed up the Alberta economy in 1948-49; there was a rise in income instead of decline. Again in 1952-53 the petroleum industry pulled income upward from what would otherwise have been a static position. Although it made a large contribution of nearly 40 per cent to Alberta income in 1954, the industry was not quite strong enough to offset entirely the slump in agriculture that year. However, it did modify the downturn greatly and Alberta income fell by only four

Table XXVIII

Estimated Personal Income in Alberta With and Without the Petroleum Industry, 1946-56

In millions of dollars

Year	Estimated Actual Personal Income[1]	Estimated Personal Income After Deducting Petroleum Industry Contribution[2]	
1946	666	655	(98)
1947	709	674	(95)
1948	870	780	(90)
1949	896	726	(81)
1950	921	681	(74)
1951	1,179	914	(77)
1952	1,253	903	(72)
1953	1,278	908	(71)
1954	1,215	745	(61)
1955	1,322	762	(58)
1956	1,539	849	(55)

[1]From DBS estimates in previous tables.

[2]The figures in brackets denote the estimated percentage of actual income remaining after removing the petroleum industry. The year 1946 is included, although it is a pre-Leduc year, for convenience of presentation. In that year the petroleum industry was a small and unimportant export industry in Alberta.

per cent whereas in Saskatchewan income fell by 30 per cent. In 1955-56 the petroleum industry gathered momentum and carried Alberta income rapidly upward without much assistance from the other "export" industries.

The plight of the Alberta economy would have been serious during recent years but for the petroleum development. According to the estimates, total personal income would have risen to a peak in 1951, about 40 per cent above the 1946 level. The decline of 1954 would have been in the order of one fifth below the 1953 level and even with the subsequent rise the level in 1956 would have been only about one quarter more than in 1946. After adjusting for a rise in prices of about one half between 1946 and 1956, one can see how lacking in growth the Alberta economy might have been.

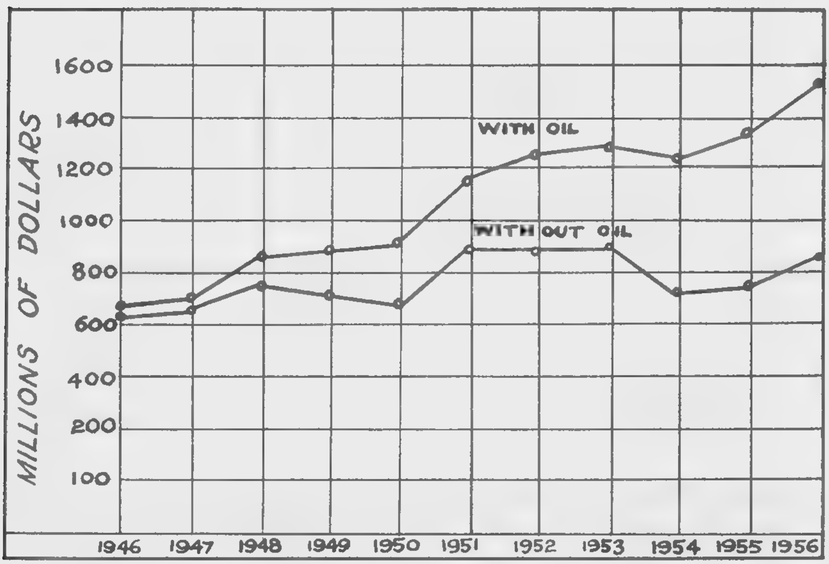


Fig. 57

As things turned out, the rising importance of the petroleum industry provided both income growth and stability. The income generated by the industry rose from about $10 million in 1946 to almost $700 million during 1956, providing an ever-widening cash flow in the Alberta economy. Even in its early stages of development the industry staved off declines in personal income in Alberta (1949-50); it did so again in 1952 and almost succeeded in doing this in 1954, a year of nation-wide adjustment which in Saskatchewan assumed the dimensions of a recession.

Changes in Income Per Capita

The development of the petroleum industry added greatly to the total population and personal income of Alberta. How did it affect the personal income per capita? To estimate per capita income "with oil" the personal income estimates in the first column of Table XXVIII were divided by the estimates of actual population in each year. To obtain estimates "without oil", the personal income estimates in the second column of Table XXVIII were divided by the estimates of Alberta population "without oil". Table XXIX sets out the results.

Table XXIX

Estimated Personal Income Per Capita in Alberta With and Without the Petroleum Industry, 1946-56

In dollars

Year	Estimated Actual Personal Income Per Capita[1]	Estimated Personal Income Per Capita Without the Petroleum Industry[2]	Additional Income Per Capita "With Oil"
1946	830	820	10
1947	860	840	20
1948	1,020	975	45
1949	1,010	910	100
1950	1,010	850	160
1951	1,255	1,145	110
1952	1,290	1,135	155
1953	1,265	1,150	115
1954	1,160	950	210
1955	1,215	980	235
1956	1,370	1,095	275

[1]Estimated actual personal income in each year as per column 1 in Table XXVIII divided by the estimated actual population in each year (census and intercensal estimates).

[2]Estimated personal income in each year if there had been no oil development and as per column 2 in Table XXVIII divided by a population of 803,000 (actual) in 1946, by 800,000 for 1947-51, by 795,000 in 1952, by 790,000 in 1953, by 785,000 in 1954, by 780,000 in 1955 and by 775,000 in 1956.

First of all, the actual personal income per capita—"with oil"—increased from $830 to $1,370 between 1946 and 1956, a rise of 65 per cent. "Without oil" the increase would presumably have been from $820 to $1,095, a rise of only 33 per cent. Second, the income per capita added by the petroleum industry rose from an estimated $20 in 1947 to an estimated $275 in 1956. There were annual variations which can be studied by reference to Table XXIX. The estimated additions to income per capita arising from the development of the petroleum industry, however, cannot be considered complete without examining the greatly expanded revenues of the provincial government. To this we shall turn presently and then recapitulate the growth of the Alberta economy in terms of population, income and income per capita for the decade 1946-56.

The following table is indicative of the great increases in the goods and services and amenities enjoyed generally by Alberta residents after 1946:

Percentage increase, 1946-56	
Motor vehicles registered	170
Telephones in use	170
Electric power generated	236

Departing from the quantitative for a moment, there is an emphasis placed by large numbers of Albertans today upon expensive spacious housing which only relatively few could indulge in 10 years ago. There is great stress put upon the possession of new cars. Almost every day someone is off on a trip to Europe or other distant parts; 10 years ago such trips by Albertans were a comparative rarity and travelling agencies were virtually unknown. Week-enders at the lake resorts around Edmonton during the summer are involved in bumper-to-bumper driving; 10 years ago relatively few could afford to make such jaunts periodically. Alberta teams have captured the Canadian championship in professional football four times since 1948 and the Edmonton team has won three in a row since 1954.

It would be possible to go on. These manifestations are apt to exaggerate the benefits of oil and to indicate some of the drawbacks of prosperous, urbanized ways of living. What is fundamental here is that living standards have risen greatly in Alberta since 1946 and that goods and services enjoyed by relatively few 10 years ago are now taken for granted by the many.

The Revenues of the Government of Alberta

The achievements in provincial public finance in Alberta constitute a special story. The data are available in the provincial public accounts and in budget speeches by the provincial treasurer throughout the decade 1947-56. Here a summary is provided from these sources.

During the fiscal year ended March 31, 1947, the Alberta government collected $45 million in revenue. With the development of the petroleum industry revenues rose rapidly and large surpluses were realized annually. During the fiscal year ended March 31, 1957, the government collected more than $250 million in revenue. The large increases in revenue after 1947 were primarily the result of lease rentals and purchase prices of rentals and royalties. These receipts currently provide nearly half of the government revenue. In addition, the prosperity generated by the petroleum industry increased the yields of other revenue sources.

It is likely that if there had been no oil development the revenue in the fiscal year 1956-57 would have been about $85 million, not much more than one third of the total actually realized. Such a level would have been in line with the actual revenue levels of Saskatchewan and Manitoba.

A summary of the fiscal achievement of the Alberta government for the 10-year period beginning April 1, 1947, shows that it collected total revenues of $1,540 million of which nearly $625 million, or about 40 per cent, was derived directly from the petroleum industry. Approximately $200 million may be regarded as revenue induced by the rise in income resulting from oil development. The balance was revenue which the government would have received in any event.

The revenue was used in various ways. The table on p. 276 is indicative.

About $850 million, or 55 per cent of the total, was used for expenditures on roads, education, health and welfare, debt charges and many other purposes.

During the 10 years in question the urban local governments became hard-pressed financially because of the rapid growth of the urban population. To obtain funds they raised tax rates and sold bonds and debentures in the capital markets outside Alberta. Between 1946 and 1950 the debt of all the local governments increased from $37 million to $81 million. In 1950 the provincial government began to come to the rescue by providing increasing amounts of loan funds and between that year and early 1957 it lent about $200 million to local governments, nearly

all of their debt increase for that period. A very large part of the local government debt of the province is now held by the provincial government.

The provincial government also increased its grants to the local governments. These rose from about $9 million in fiscal 1947-48 to about $65 million in fiscal 1956-57, and totalled approximately $315 million for the decade.

Table XXX

Uses of the Revenues of the Government of Alberta for the Ten-Year Period Beginning April 1, 1947, and Ending March 31, 1957

In millions of dollars

Expenditures, including debt reduction	851
Grants to local governments	315
Loans to local governments	200
Loans to Alberta Government Telephones	52
Loans for rural electrification	12
Net increase in cash and investments exclusive of loans above	110
Total revenue	1,540

Altogether, then, the provincial government used about $515 million, one third of its revenues for the decade, to assist the local governments. The total was not far from half of the estimated $1,100 million spent by the local governments during the decade both on current and capital accounts.

Substantial loans were also made by the provincial government for the extension of rural electrification and telephone facilities. At the same time the government built up a large portfolio of Government of Canada and other bonds. Finally, it reduced the provincial debt materially during the decade. Table XXXI shows the changes in liquid assets and the provincial debt between March 31, 1947 and December 31, 1956.

The government could have liquidated its debt in the early 1950's by selling its investment holdings. However, it was earning a higher rate of interest on its investments than it was paying on its own highly creditworthy bonds.

A total revenue of $253 million (including $8 million of capital receipts) is estimated for the fiscal year 1957-58 by the Hon. E. W. Hinman, Treasurer of the Province of Alberta. Practically all of this is expected to be spent. Direct grants to local governments are estimated at $72 million, and another $30 million was set aside for loans to the local governments. An unusual measure was the earmarking of one quarter of the estimated revenue from the petroleum royalties to be disbursed to

Table XXXI

Changes in Cash and Investments and the Provincial Debt of the Government of Alberta March 31, 1947 to December 31, 1956

In millions of dollars

	Cash and Investments[1]	Provincial Debt[2]	Net Debt[3]
March 31, 1947	27	145	118
December 31, 1956	338	85	–253

[1]Includes bank balances, holdings of Government of Canada securities and the securities of other governments, loans to Alberta local governments, loans for rural electrification, loans to the Alberta Government Telephones and miscellaneous loans.

[2]Includes both funded and unfunded debt.

[3]This item equals provincial debt minus cash and investments.

Alberta residents in late 1957. About $10 million will be distributed among an estimated 500,000 residents ($20 each) who have attained the age of 21 and who fulfil certain residence requirements. Payments will be made upon application by residents at banks and other fiscal agencies in the province. Recently the government announced its intention to reduce the provincial debt by about $50 million, leaving only a token debt.

Provincial-municipal relations are undergoing intensive study to determine the best use of the revenues of the provincial government. Surpluses have been realized for many years, but the government is now finding that expenditures are running very close to revenues. It is living up to its income as a result of numerous demands for local government grants and loans for government services generally.

During the first three months of 1957 more than $33 million of petroleum revenue was collected. The revenue from lease rentals will continue

to be substantial in the future in the light of the large areas which will be held by oil and gas companies for exploration purposes in the years to come. The competition among the companies for prospective acreage is keen in many areas, and they do not let reservations and leases go without much hesitation. The revenue from the auctioning of leases will continue to be large, but it will be variable because of the uneven rate at which oil

Table XXXII

Revenue of the Government of Alberta from Petroleum Rights, by Calendar Year, 1947-56

In millions of dollars

		Lease Rentals	Sales of Crown Reserves	Royalties	Total
Year	1947	0.6		0.8	1.3
	1948	2.0	3.1	1.4	6.5
	1949	5.0	19.8	3.3	28.1
	1950	8.6	36.3	4.9	49.7
	1951	14.4	15.1	10.0	39.5
	1952	18.0	22.4	12.9	53.2
	1953	21.1	22.8	16.3	60.2
	1954	24.4	64.9	19.7	108.9
	1955	20.5	62.4	26.1	109.0
	1956	25.0	72.7	35.4	133.1
	Total for Decade	139.5	319.4	130.8	589.5

Source: Government of Alberta, Department of Mines and Minerals.

and gas fields are found. Royalty revenue will rise with the increasing output of oil and gas; short-run downturns can be expected in years when there are difficulties in marketing oil. The export of natural gas will enhance the value of leases and add to royalty revenue during the next decade. The revenue of the provincial government from lease rentals, auctioned leases and royalties is likely to reach $150 million in a few years. A total provincial government revenue exceeding $300 million is not out of the question some time during the next decade.

The Benefits to Alberta Residents

The revenues collected from the petroleum industry consisted of funds which were derived mainly from non-residents. The spending of these funds for a variety of government services generated personal income which would not have materialized otherwise. If the government had been forced to raise the same revenue by taxing Albertans it would have depressed their ability to spend on consumer and capital goods. Virtually nothing would have been added to the income of Alberta residents by the expenditures from such funds because it would have mainly been a case of substitution of government spending for the spending of individuals. Instead, the government spent non-resident funds, generating additional personal income for Albertans. These increments and their effects have been considered previously.

Albertans enjoyed a higher level of government goods and services and their provincial government was able to reduce much debt and build up a sizeable investment portfolio because of the receipt of non-resident funds through the petroleum industry. It remains to estimate the additions to the economic well-being of Alberta residents represented by these collective benefits.

It was estimated in a previous chapter that about four fifths of the government revenue from the petroleum industry was obtained from non-resident sources. Table XXXII shows the total revenues collected from petroleum sources during the decade. Taking four fifths of these revenues in each year, the following estimates of the value per capita of collective goods and services added by the petroleum revenues from non-residents emerge:

Value per capita in dollars

1947	1	1952	43
1948	6	1953	48
1949	26	1954	84
1950	44	1955	82
1951	34	1956	94

The contributions of the petroleum revenues to the provincial treasury are reflected in a number of ways. Many new schools and hospitals have been constructed in Alberta since 1946. The facilities of the provincial university have been expanded. Thousands of miles of surfaced roads have been constructed during the decade. Tens of thousands of farms

have been provided with electricity, thanks to loans by the provincial government. More small towns and villages with only a few hundred people are said to be served by water works and sewage facilities than in any other province, thanks also to low-interest loans provided by the provincial government. On the cultural front, a magnificent provincial auditorium has been constructed in Edmonton and another in Calgary to commemorate the golden jubilee of the province.

Summary

At the beginning of the chapter it was estimated that the additional per capita income resulting from the development of the petroleum industry in Alberta was $275 in 1956. At the end of the chapter it was estimated that government services valued at $94 per capita were provided as a result of the development of the industry. Some residents, particularly farmers, also received royalties from oil production, cash bonuses and fees for leases. These averaged nearly $10 per capita in 1956. To this a further $25 per capita could be added, a tentative measurement of the income effect of the difference in the prices of petroleum products "with" and "without oil". On the basis of these estimates the value per capita of benefits accruing to Albertans in 1956 as a result of the petroleum industry development approached $400.

Because of the development of the petroleum industry since 1946, the Alberta economy supported an estimated 320,000 more people in 1956 than it would have done without this development. The expanded population enjoyed a level of economic well-being per person which was an estimated one third above that which would have been enjoyed, on the average, by a considerably smaller number of people if there had been "no oil". In short, there are more Albertans than there would have been and, on the average, they are better off.

24.

Population and Employment Effects

One index of economic growth is population change although it does not always reflect the economic welfare of a region. In North America, however, population growth generally does mean that the region concerned offers superior occupational opportunities and prospects of a rising level of living. Population decline usually suggests that a region offers insufficient opportunities and even that its level of living may fall. In any event, before we can interpret the income changes in Alberta and indicate what income per capita would have been "with oil" and "without oil", we need to survey the population changes that took place.

The Population Increase in Alberta

Before 1946 Alberta was losing people at an accelerating rate. Between 1931 and 1936, the natural increase (number of births minus number of deaths) was about 55,000 but the population increased by only 41,000, from 732,000 to 773,000 people. This indicated a net loss of 14,000 people to other regions. Between 1936 and 1941 the population rose by 23,000 to 796,000. The natural increase was an estimated 52,000 people, and the net loss to other regions appears to have been about 29,000, more than twice the number lost during the previous five years. Finally, between 1941 and 1946 the population rose by only 7,000 to 803,000 despite an estimated natural increase of over 60,000; the net loss to other regions was more than 50,000, not far from twice the number lost during 1936-41.

Population decline appeared to be in store for Alberta after 1946. With the increasing economic opportunities offered outside the prairie region, Albertans were moving out in rising numbers. It is probable that without the petroleum development the population of the province would have remained at about 800,000 during the immediate postwar years when agriculture was prosperous. This implies that all of the natural increase would have been lost to other regions. Quite possibly the province might have lost even more people and the population might have been less than 800,000 by 1951. During the 1950's when agriculture became less prosperous, decline would most likely have occurred, and by 1956 the population might have dropped to 775,000 or even to 750,000.

The Leduc discovery immediately changed the outlook. Many Albertans shelved indefinitely their plans to move to British Columbia, Ontario and the United States, the most popular destinations of migrating Albertans. Many prodigal sons returned from these regions, and the province began to attract a considerable number of migrants from Saskatchewan and Manitoba. Oil companies like Imperial and British American repatriated most of their personnel in South America and the United States respectively. The stimulus that the petroleum industry gave to investment and production in nearly all industries increased and variegated the opportunities for employment in the province. The end result was that the population rose from 803,000 to 1,123,000 between 1946 and 1956, an increase of 320,000. The natural increase, represented by the number of births less the number of deaths was more than 210,000, indicating a net inflow of migrants of nearly 110,000. Table XXXIII sets out the annual changes for the decade.

The rate of population growth in Alberta was 40 per cent for 1946-56, a rate exceeding that of any other province although British Columbia ran a very close race, and it was much above the Canadian average of 27 per cent. The sister provinces of Manitoba and Saskatchewan registered increases of 17 per cent and six per cent respectively during the decade.

The population of Manitoba had decreased from 730,000 to 727,000 from 1941 to 1946. Between 1946 and 1951 it increased by 49,000 to 776,000. Practically all of this increase was attributable to the growth of Metropolitan Winnipeg from 307,000 to 354,000 people. Winnipeg is the traditional wholesaling and financial centre of the prairies and much of its population increase was induced by the rapid development of the petroleum industry in Alberta. After 1951 the petroleum industry began a relatively intensive exploration and drilling program in Manitoba. The population increased by 74,000 to 850,000 during the 1951-56 period as Metropolitan Winnipeg grew further with the development of the petroleum industry throughout the prairie region and oil towns like Virden experienced rapid population increases.

In Saskatchewan the population fell from 896,000 to 883,000 between 1941 and 1946 and it fell further to 832,000 in 1951. After that the petroleum industry began a large program of exploration and drilling in the province and the decline was reversed almost at once. Between 1951 and 1956 the population rose by 49,000 to 881,000.

Table XXXIII

Population Change in Alberta, 1946-56

Year	Total Population 000's	Annual Increase 000's	Rate of Annual Increase per cent
1946	803		
1947	825	22	2.7
1948	854	29	3.5
1949	885	31	3.6
1950	913	28	3.2
1951	939	26	2.9
1952	973	34	3.6
1953	1,012	39	4.0
1954	1,051	39	3.9
1955	1,091	40	3.8
1956	1,123	32	2.9

Source: DBS, census data for 1946, 1951 and 1956; intercensal estimates for other years.

Without the oil developments in Alberta and their subsequent spread to the other two prairie provinces, the population of the three provinces would probably have been in the neighbourhood of 2.3 million in 1956. Instead it was nearly 2.9 million. It is not presumptuous to say that the petroleum industry added 600,000 people to the region.

In the prairie region of Canada the petroleum industry prevented population decline, injected a new vitality in outlook, and provided directly by its own activities and by the stimulus given other industries a broad range of economic opportunities for a growing population. It stemmed the rising exodus of youths and skilled workers to other regions, including graduates of the prairie universities. People with special talents and skills found increasing opportunities in their own region. There was also an influx of technicians, scientists and managers to make

the capital investment of the petroleum industry and other industries effective. These people also taught regional residents their skills and know-how. All told, there was not merely a population increase but also a general upgrading of the labour force, creating a potential for the generation of new economic activities and the acceleration of further economic development.

The reader can imagine for himself the political consequences if the petroleum industry had not stimulated the economy of the prairie region. There would have been two major "problem" areas in the Canadian federation, the Atlantic and the prairie provinces, a situation which would have done nothing to maintain and further Canadian national unity.

Table XXXIV

Population Changes by Type of Communities in Alberta, 1946-56

In thousands of people

	1946	1956	Increase	Percentage Increase
Metropolitan Edmonton and Calgary	223	445	222	100
All other centres with more than 1,000 people	75	160	85	114
The rest of Alberta	505	518	13	3
Total Alberta	803	1,123	320	40

Source: DBS, census data.

The Urban Population Growth in Alberta

The urban centres of Alberta absorbed most of the population increase of the province during 1946-56. Edmonton and Calgary became the fastest-growing metropolitan areas in Canada. Edmonton, which was the ninth largest city in Canada before the oil development, became the sixth largest by 1956, surpassing Windsor, Quebec City and Ottawa. If its present rate of growth is maintained through 1956-61, it will become Canada's fourth city by 1961, exceeding Hamilton and Winnipeg, assuming that the current rates of growth for these cities are maintained. Calgary which ranked tenth before the great oil development surpassed Windsor and Quebec City to rank eighth in 1956.

Table XXXIV summarizes the changes in the distribution of the population in Alberta in 1946-56.

The urbanization attending the oil development was clearly marked. In 1946 Metropolitan Edmonton and Calgary had 28 per cent of Alberta's population; in 1956 they had 39 per cent of a greatly expanded provincial population. If we lump together all centres with more than 1,000 people, we find that they had 54 per cent of the provincial population in 1956 as against only 37 per cent in 1946. The people of Alberta, then, have rapidly become urban dwellers with all the amenities and problems that go with city life.

The development of the petroleum industry was not responsible for the urban trend, although it undoubtedly accelerated it. The cities and towns of Alberta would have grown considerably even in the absence of the oil discoveries, but not nearly so much as actually happened.

By 1946 Metropolitan Edmonton had 15 per cent of Alberta's population; the great growth of the provincial economy generally and the induced effects of the marked concentration of oil fields around the city gave it 22 per cent of the provincial population in 1956. Metropolitan Calgary had 13 per cent of the Alberta population in 1946 and 17 per cent in 1956.

All centres with a population exceeding 1,000 (which can be termed urban) had 37 per cent of the Alberta population in 1946. With the "agricultural revolution" which was mechanizing farms in a high degree, increasing the average size of farms and diminishing their number, and raising the productivity of the farm labour force, an expansion of the urban population was taking place before 1946. An increasing number of farm operators were also moving into the towns with their families; so were a rising number of retired farmers. By 1956 these urban centres had 54 per cent of the population. The urbanization would have been less marked without oil since the average income per person in Alberta would have been lower and the development of specialized services for both consumer and capital goods industries would have been less intense, requiring fewer urban workers than otherwise.

It is notable that 25 out of 61 centres with a population of more than 1,000 in 1956 more than doubled their populations in 1946-56. Some of these, such as Devon, Redwater and Drayton Valley, had very few or no people in 1946 and their growth was entirely and directly oil-induced. Others were centres of some importance in 1946. Among these, Fort Saskatchewan, Grande Prairie, Leduc, Lloydminster, Red Deer, Stettler and Wainwright owe much of their increase to oil. Many other towns grew because of oil developments. Even the location of an important air force defense base at Cold Lake may have been induced by the ready availability in Alberta of petroleum products.

Only a few centres registered declines in population. Of these, two were coal-mining centres, Coleman and Drumheller. The other was Turner Valley whose population fell from 1,157 to 670 between 1946 and 1956.

The development of the petroleum industry had uneven effects upon various centres. By and large, the largest centres grew most rapidly and so did those in or near the major oil fields. If the petroleum development had not occurred, the larger centres would still have grown more than the smaller because they offer more opportunities and a greater fascination for youngsters off the farm and more amenities for retired farmers.

Table XXXV

Employment in the Petroleum Industry and Related Industries in Alberta, 1946 and 1956

In thousands

	1946	1956	Increase
Administration, exploration and drilling	2.0	12.5	10.5
Operation of wells	0.1	2.2	2.1
Pipe lines and related services	0.1	1.5	1.4
Other production services	0.1	1.5	1.4
Petroleum refining	0.6	2.0	1.4
Gas manufacture and distribution	0.5	1.2	0.7
Automobile repair and garages	5.4	7.0	1.6
Gasoline, lubricating oils and greases, retail	1.1	1.4	0.3
Gasoline, lubricating oils and greases, wholesale	1.0	1.8	0.8
Petrochemicals	0.2	2.2	2.0
Total	11.1	33.3	22.2

Sources: Estimates made by the writer from data of the Alberta Bureau of Statistics and the DBS.

Employment Effects

The petroleum industry is not in itself a large employer of labour. In 1946 the total number of employees in administration, exploration, drilling, well operation, pipe line operation, miscellaneous contracting services, refining, gas manufacturing and distribution, petrochemical manufacturing and marketing of petroleum products was an

estimated 11,000. This was about three and a half per cent of the labour force. It contained some overlapping activities since many garage employees are also automobile mechanics as well as sellers of gasoline. By 1956 the total had risen to an estimated 33,000, about eight per cent of the labour force in Alberta. Table XXXV shows the details.

It is clear that the labour force of the petroleum industry itself earned only a part of the income generated by the industry's activities. The industry is a large spender on a variety of goods and services, and to list all the employments affected by its spending would be tedious. We need cite only three instances.

Table XXXVI

Estimated Changes in the Relative Importance of Employment in Different Industries in Alberta, 1946 and 1956

Employment in each industry as a per cent of the total labour force

	1946	1956
Agriculture, primary	40.2	26.0
Forestry and logging	0.6	0.5
Fishing and trapping	0.5	0.3
Mining	3.4	4.0
Manufacturing	9.2	11.0
Electricity, gas and water	0.6	1.0
Construction	4.3	7.8
Transportation, communication and storage	7.1	7.0
Retail and wholesale trade	9.9	13.7
Finance	1.7	2.6
Services	21.3	25.5
Not stated	1.3	0.5
Total percentage	100.0	100.0
Estimated labour force (in 000's)	302	416

Sources: Estimated from the data of the Alberta Bureau of Statistics and the DBS.

First, many thousand workers were added to the wholesale and retail trades to supply the petroleum industry with machinery, equipment and materials. Many more were added to the labour force to service the machinery and equipment and many were added in the transportation industries to transport the equipment and supplies. These workers and their employers were direct recipients of petroleum-industry expenditures. So

also were workers engaged in constructing temporary buildings and roads in the oil fields. Second, the provincial and local governments, financed to a large extent by the petroleum industry through land payments and royalties, engaged a growing number of administrative, clerical and construction workers. The numbers run into tens of thousands. Third, the investment of the petroleum industry in pipe lines, refineries, natural gas plants and petrochemical plants added thousands of workers to the construction industry.

Finally, the addition of all these workers who depended more or less directly upon the expenditures of the petroleum industry, led to the addition of workers in nearly every kind of industry and occupation. These workers provided manufactured goods and transportation, public utility, retailing, wholesaling, financial, professional, community and personal services for the growing population. Many workers were engaged in the construction of homes, apartments, hotels, commercial buildings and factories.

In the process of income and population growth there were great changes in the structure of the labour force. Estimates are shown in Table XXXVI. Since these are shown as percentages, they indicate changes in the relative importance of each industry.

The direct employment in the petroleum industry is not classified separately but is included under such categories as mining, manufacturing, construction and transportation. The employment induced by the petroleum industry is scattered throughout all the classifications. Generally speaking, there was a growth in the number of workers in industries providing higher earnings and a decline in industries like agriculture that, on the average, offered inferior returns to operators and employees. The relative decline in employment in primary agriculture is notable. The number of full-time wage earners in agriculture is relatively small and so the decline in employment was largely a reduction in the number of farm operators and part-time workers.

The Alberta labour force became increasingly composed of employees in urban occupations and in the petroleum industry. Wages and salaries more than trebled in 1946-56. In 1946 wages and salaries were 42 per cent of total personal income; by 1956 they were 59 per cent. The table on the next page indicates the change in the importance of this kind of income by reference to other income and to total personal income.

The petroleum industry itself pays higher wages than any other industry. Most other industries pay higher wages than are attainable by the earnings of the bulk of farm operators and their employees. The petroleum industry has, both directly and indirectly, presented Albertans with a wide variety of employment opportunities as employees or entrepreneurs in activities yielding income which make a high and stable

In millions of dollars

	1946	1956	Percentage Change
Wages and salaries[1]	281	901	222
Other personal income[2]	385	638	65
Total personal income	666	1,539	130

[1]Includes supplementary labour income.

[2]Net income received by farm operators from farm production, net income of non-farm unincorporated business, interest, dividends, net rentals and government transfer payments.

Source: DBS, *National Accounts, Income and Expenditure.*

standard of living possible. This is in contrast to the possibilities that presented themselves before Leduc when it appeared that Alberta would be losing a large number of its youthful, skilful and enterprising residents.

25

Concluding Observations

Many years ago Adam Smith examined the conditions of wealth in new countries. Essentially they have "more land than they have stock (capital) to cultivate". According to Smith, "the most decisive mark of the prosperity of any country is the increase of the number of its inhabitants" and "it is not . . . in the richest countries, but in the most thriving, or in those which are growing rich the fastest, that the wages of labor are highest". Presumably, the new country forges ahead when there is a great increase of capital ("stock") and population.

Just as the development of the agricultural potential of Alberta's land led to rapid settlement and new employment and income opportunities half a century ago, so the petroleum potential has induced a great rise in population and income at mid-century. In both cases a high rate of economic progress was made possible by substantial inflows of capital and labour.

The development of the petroleum potential gave Alberta a "dynamic decade". But it did more than this. It built a second major export industry into the provincial economy, adding to its size and increasing its stability. During the decade there was a large inflow of capital funds, principally to finance petroleum development and also to invest in a variety of other activities. The expenditure of the funds enlarged the income of the province and led to population growth. In the process, a new export staple, crude oil, was produced and sold abroad in rapidly rising quantities. The sale of crude, too, added significantly to provincial income especially as most of the proceeds were reinvested in the region.

In the future activities of the petroleum industry the relative importance of capital inflows may diminish while the proceeds from crude oil sales become more important. An outward flow of dividends and federal

income taxes may be expected. But as long as there is a reasonable possibility for discovery and a probable market for crude oil, funds for exploration and development will be forthcoming in volume. Additional spending by the industry will be forthcoming with the export of natural gas.

A remarkable feature of Alberta's development in the past decade is that it has been achieved without a legacy of external debt and contractual obligations. In bad times, these would have imposed a serious drain of funds from the region in the form of debt charges. This is in contrast to the conditions accompanying the province's agricultural development. After the First World War the new agricultural industry, the provincial government and a number of urban local governments faced heavy fixed payments on external debt. These proved critically high in the two decades that followed.

During the past decade of petroleum development, the provincial government has provided facilities and services for a growing population without resort to borrowing. It has also lent the local governments most of the money that they have borrowed, thus making the municipal debt largely internal. The petroleum industry provided funds by its payments to the government for land. The industry itself relied heavily upon equity capital. Dividends and income taxes will tend to draw funds from the region as the industry prospers. However, these are the fruits of achievement and are not fixed in amount like debt charges that must be paid in both good times and bad.

Various estimates by experts point to continuous, long-term growth of the world consumption of oil and gas. The large reserves of the Middle East will be in great demand to supply Western Europe whose continued economic progress will depend greatly upon its ability to obtain oil. This, in turn, will depend upon the extent to which the Middle East can be relied upon, especially in the light of its disturbed political state.

The long-term outlook for the petroleum industry in North America is bright. We can expect that the United States will increase its imports in the long run since its consumption is rising rapidly while it is becoming increasingly difficult to find new reserves. By 1960 the United States is expected to consume 10 million barrels of oil per day, enough to exhaust the original recoverable reserves of the Leduc-Woodbend field within a month. Although major fields are becoming more difficult to find in the U.S.A., Alberta is likely to have a larger quota of such fields left than almost any other area on the continent.

In 1956 Alberta exports to the United States were equal to about one per cent of the consumption in that country. If Alberta crude oil could provide three to four per cent of the United States demand and continue

to expand sales within Canada, one can foresee an output of a million barrels per day from Alberta fields some time during the 1960's. The current restrictions of the United States upon imports may be viewed as a short-run phenomenon which, of course, will tend to make the market outlook somewhat uncertain.

Estimates made in various submissions to the Gordon Commission suggest that from 20 to 30 billion barrels of oil will be found in Western Canada by 1980. This implies a finding rate of almost one billion barrels per year on the average. During 1947-56 the average was less than half a million barrels per year. To find the quantity of oil foreseen in the submissions, a high level of spending on exploration and development will be required. Estimates of the capital expenditures needed for this run from 15 to 25 billion dollars for the period 1956-1980.

The Gordon Commission itself estimates that the total capital expenditure for all purposes of the petroleum industry in Canada, from exploration to marketing, could well be 25 billion dollars for the quarter century beginning with 1956. That commission also has indicated that the potential production of crude oil in Canada may be ten times as great in 1980 as it was in 1955 and that petroleum and natural gas may furnish from two thirds to three quarters of the energy consumed in Canada. Much of this expected expansion in the petroleum industry will take place in Alberta by virtue of the degree of development of the industry in the province as well as its large sedimentary area. The various estimates also indicate that the 1947-56 decade, spectacular though it was, marked only a beginning of the development of the Canadian petroleum industry.

Regarding the outlook for competitive fuels, there is the possibility of growth in the use of nuclear power by the 1970's. However, the Gordon Commission has estimated that it will provide only about two per cent of Canada's energy requirements by 1980. Coal, the great energy source of the past hundred years or more, is expected to continue to decline in relative importance. The Gordon Commission has estimated that coal will provide about 16 per cent of Canada's energy requirements in 1980 as against 39 per cent in 1955. The immediate decades ahead, then, promise to be a petroleum era.

Any readily available substitute for crude oil must have a bearing on the petroleum industry. In this regard, the Alberta tar sands are receiving continuing attention. There is little to say about the prospective development of processes that might become competitive with the conventional production of oil. However, when such methods are developed, they will come gradually and will be more likely to supplement, rather than displace, present sources.

Great strides have been made in recent years in devising economic secondary recovery from existing pools. It appears that just as much oil

and more may be recovered in this manner as may be found and produced by primary methods from new fields.

While space does not permit us to delve into all the factors bearing upon the future of the petroleum industry in Alberta, perhaps a few general comments may suffice. Firstly, with growing world and national demands for the products of oil, production is assured of an expanding market. As a result, a high level of capital spending can be expected far into the future. The coming expansion of natural gas sales will add to both stability and income. New markets for natural gas will provide further incentive for land sales and for exploration and development. All of these will bring to the provincial government an increasing flow of revenues, from land sales, rents and royalties. New industries will come to Alberta, attracted by a growing market and a ready supply of raw materials. This is indeed an optimistic picture; it can be damaged, or deferred, however, if governments postpone for too long any decisions regarding export of natural gas. Foreign markets denied supplies from Canada will seek gas or its substitutes elsewhere. Thus markets may be lost and development delayed. The large coal reserves that lie under Alberta's soil are mute evidence of how little is the value of "resources" when demand is lacking.

The petroleum industry can be expected to make a major contribution to the income of Alberta in future years. Projections based on forecasts of either the oil industry or of the Gordon Commission point to a very substantial income growth.

The Alberta economy is no longer highly dependent upon the export of any one staple. Less than one fifth of its income is subject to the vagaries of wheat growing. Another fifth or so is derived from livestock raising and processing, activities which are relatively stable. About one quarter is generated from the land acquisition, exploration and development activities of the petroleum industry. A fifteenth is provided by the producing operations of the petroleum industry and by its capital and operating expenditures for transportation, refineries, natural gas plants and petrochemical plants. Finally, there is a miscellany of activities, many of which are derived from oil operations, providing the rest of the income of the province.

The large imports associated with the development of the last decade provide a challenge to investors and entrepreneurs. Considerable investment in some industries in Alberta to produce goods regionally that are now imported may occur. However, a high degree of self-sufficiency cannot be looked for; Alberta's location precludes the economical manufacture of a great many commodities. The major basis for the development of Alberta lies in its potential natural resources. Regions are mutually interdependent, and it makes sense for a region to export those goods in which it has comparative advantages and to import those in which it has

comparative disadvantages. Intense regionalism, translated into the policies of regional governments, could modify the pattern of development, but it would mean doing less of what comes naturally and doing more of what comes hard. The price paid would be a slower rate of progress than that experienced when the path of comparative advantage is followed.

For Alberta one can see continuing petroleum development and an increasingly stable agricultural industry. Petroleum exploration activities and the long-run demand for northern minerals will tend to push the frontier northward. The development of the resource potential of the northland of the continent has only begun. Alberta has participated in northern development in the past. Today, with an economy strengthened by a vigorous petroleum industry, the province is in a position to play a major role in the opening up of Canada's northern frontiers. The petroleum industry itself can be expected to furnish much of the initiative and a large part of the funds and products required to promote the economic progress of the great northland of our continent. The development of both Alberta and the petroleum industry since Leduc provided a large bridge which may save decades of time in the assault upon the potential wealth of the north.

Bibliography

General Works on Economics

The following books provided information and ideas in various ways:

Alderfer, E. B. and Michl, H. E., *Economics of American Industry* (second ed.), New York and London.

Britnell, G. E., *The Wheat Economy*, Toronto, 1939.

Clark, Colin, *Conditions of Economic Progress* (second ed.), 1951.

Cohn, E. J. Jr., *Industry in the Pacific Northwest and Location Theory,* New York, 1954.

Haley, Bernard F. (ed.) and thirty contributors, *A Survey of Contemporary Economics,* vol. II, Homewood, Ill., 1952.

Hartland, Penelope, *Balance of Interregional Payments of New England,* Providence, 1950.

Hedges, J. B., *Building the Canadian West*, New York, 1939.

Hegeland, Hugo, *The Multiplier Theory*, Lund, Sweden, 1954.

Hoover, E. M., *The Location of Economic Activity*, New York, 1948.

Innis, Harold, *Problems of Staple Production in Canada*, Toronto, 1933.

Keirstad, B. S., *The Theory of Economic Change*, Toronto, 1948.

Keynes, John Maynard, *The General Theory of Employment, Interest and Money*, New York, 1936.

Le Bourdais, D. M., *Canada's Century*, Toronto, 1956.

Lewis, W. Arthur, *The Theory of Economic Growth*, London, 1955.

Mackintosh, W. A., *Economic Problems of the Prairie Provinces*, Toronto, 1935.

——, *Prairie Settlement, The Geographical Setting,* Toronto, 1934.

National Bureau of Economic Research, *Regional Income*, Studies in Income and Wealth, vol. 21, Princeton, 1957.

Ohlin, Bertil, *Interregional and International Trade*, Cambridge, Mass., 1935.

Schumpeter, Joseph A., *The Theory of Economic Development*, Cambridge, Mass., 1934.

Smith, Adam, *Wealth of Nations,* 1776 (Modern Library ed.)

van der Valk, H. M., *Economic Future of Canada*, Toronto, 1954.

Viner, Jacob, *Canada's Balance of International Indebtedness, 1900-1913*, Cambridge, Mass., 1924.

White, C. Langdon and Foscue, Edwin J., *Regional Geography of Anglo-America* (second ed.), New York.

Zimmerman, Erich W., *World Resources and Industries*, New York, 1951.

General Works on Petroleum

A.P.I., *Finding and Producing Oil*, Dallas, 1939.

——, *Oklahoma, The State That Oil Built*, New York, 1947.

——, *Secondary Recovery of Oil in the United States* (second ed.), New York, 1950.

Ayres, Eugene, *Major Sources of Energy*, A.P.I., New York, 1948.

—— and Scarlott, Charles A., *Energy Resources—The Wealth of the World*, New York, 1952.

Ball, Max W., *This Fascinating Oil Business*, Indianapolis and New York, 1940.

Beaton, Kendall, *Enterprise in Oil, A History of Shell in the United States*, New York, 1957.

Bell, H. S., *American Petroleum Refining* (third ed.), New York, 1945.

Buckley, Stuart E. (ed.) and fifteen contributors, *Petroleum Conservation*, New York, 1951.

Clapp, F. G. *et al*, *Petroleum and Natural Gas Resources of Canada*, Ottawa, 1915.

Committee on Reservoir Development and Operation of the Standard Oil Company (New Jersey), Affiliated Companies and the Humble Oil Refining Company, *Joint Progress Report on Reservoir Efficiency and Well Spacing*, n.p., 1943.

Dobrin, Milton B., *Introduction to Geophysical Prospecting*, New York, 1952.

De Golyer, E. (ed.), *Elements of the Petroleum Industry*, New York, 1940.

Dunstan, A. E. (managing editor) and many contributors, *The Science of Petroleum*, 6 vols., London and New York, 1938-1953.

Ells, S. O., *Bituminous Sands of Northern Alberta*, Ottawa, 1926.

Fanning, Leonard M., *Our Oil Resources*, New York, 1945.

Hager, Dorsey, *Practical Oil Geology*, New York, 1951.

Interstate Oil Compact Commission, Engineering Committee, *Oil and Gas Production*, Norman, Oklahoma, 1951.

Lahee, Frederic H., *Field Geology* (fifth ed.), New York, 1952.

Levorsen, A. I., *Geology of Petroleum*, San Franscisco, 1956.

Longrigg, Stephen H., *Oil in the Middle East*, London, New York, Toronto.

Manne, Allan S., *Scheduling of Petroleum Refining Operations*, Cambridge, Mass., 1956.

Paine, Paul, *Oil Property Valuation*, New York, 1942.

Pirson, S. J., *Elements of Oil Reservoir Engineering*, New York, 1950.

Pratt, Wallace E., *Oil in the Earth*, Laurence, Kansas, 1942.

—— and Good, Dorothy (eds.) and twenty contributors, *World Geography of Petroleum*, Princeton, 1950.

Rister, Carl C., *Oil! Titan of the Southwest*, Norman, Oklahoma, 1949.

Schackne, Stewart and Drake, N. D'Arcy, *Oil for the World*, New York, 1955.

Shell Oil Company of Canada, *The Canadian Petrochemical Industry*, Toronto, 1956.

Shuman, Ronald, *The Petroleum Industry, An Economic Survey*, Norman, Oklahoma, 1940.

Stockton, John R., Henshaw, Richard C., Jr., and Graves, Richard W., *Economics of Natural Gas in Texas*, Austin, Texas, 1952.

Uren, L. C., *Petroleum Production Engineering* (fourth ed.), 2 vols., New York, 1953.

Waller, Robert E., *Oil Accounting, Principles of Oil Exploration and Production Accounting in Canada*, Toronto, 1956.

Wolbert, George S., Jr., *American Pipe Lines*, Norman, Oklahoma.

Alberta's Oil Industry, The Report of a Royal Commission appointed by the Government of the Province of Alberta under the Public Inquiries Act to inquire into matters connected with Petroleum and Petroleum Products, n.p., 1940. (The McGillivray Report.)

Monographs and Bulletins

American Association of Oilwell Drilling Contractors, Statement for Sub-Committee on Anti-Trust and Monopoly Committee on the Judiciary United States Senate, prepared by Jack H. Abernathy, Oklahoma City, Oklahoma, February 24, 1957.

Auxier, G. W., *The Story of Oil*, Calgary, 1951.

Coqueron, Frederick G. and Pogue, Joseph E., *Investment Patterns in the World Petroleum Industry*, The Chase Manhattan Bank, New York, December, 1956.

Gilbert, Jerome, *Measurement of the Relation of Port Income to Area Income and to Area Balance of Payments*, New York, 1956 (mimeographed).

Houston Chamber of Commerce, Research and Statistics Committee, *Chemical Manufacturers in the Texas-Louisiana Gulf Coast Area*, Houston, Texas, April, 1956 (mimeographed).

Millard, Vernon, *Proration to Market Demand*, Calgary, September, 1952 (mimeographed).

Pogue, Joseph E., and Hill, Kenneth E., *Future Growth and Financial Requirements of the World Petroleum Industry*, The Chase Manhattan Bank, New York, February, 1956.

Royal Bank of Canada, Oil and Gas Department, *Oil and Gas Bulletins*, Calgary, 1956 and 1957.

Shell Oil Company of Canada, *Canadian Oil*, n.p., n.d.

Taylor, W. C. and Lindeman, John with the collaboration of Victor Lopez R., *The Creole Petroleum Corporation in Venezuela*, New York, 1955.

The Port of New York Authority, *The Port and the Community*, New York, May, 1955.

Articles on Economics and Methodology

Alexander, John, "The Basic-Nonbasic Concept of Urban Economic Function", *Economic Geography*, July, 1955.

Andrews, Richard B., six articles on "Mechanics of the Urban Economic Base", *Land Economics*, May, 1953; February, 1954; August, 1954; August 1955; November, 1955; February, 1956.

Blumenfeld, Hans, "The Economic Base of the Metropolis", *Journal of the American Institute of Planners*, No. 4, 1955.

Britnell, G. E., "Perspective on Change in the Prairie Economy", *Canadian Journal of Economics and Political Science*, November, 1953.

Daly, M. C., "An Approximation to a Geographic Multiplier", *Economic Journal*, June-September, 1940.

Hartland, Penelope, "Interregional Payments", *Quarterly Journal of Economics*, August, 1949.

Hill, Forest G., "An Analysis of Regional Economic Development: The Case of California", *Land Economics*, February, 1955.

Isard, Walter, "Interregional and Regional Input-Output Analysis: A Model of a Space Economy", *Review of Economics and Statistics*, November, 1951.

—— and Kuenne, R. E., "The Impact of Steel upon the Greater New York-Philadelphia Industrial Region", *Review of Economics and Statistics,* November, 1953.

Johnson, Keith W., "The Natural Gas Industry of the Southwest and Its Significance to Industrial Development", *Monthly Business Review of the Federal Reserve Bank of Dallas*, March, 1949.

Leven, Charles, "An Appropriate Unit for Measuring the Urban Economic Base", *Land Economics*, November, 1954.

Mackintosh, W. A., "Some Aspects of a Pioneer Economy", *Canadian Journal of Economics and Political Science*, November, 1936.

Mattila, John M. and Thompson, Wilbur R., "The Measurement of the Economic Base of the Metropolitan Area", *Land Economics*, August, 1955.

Moore, F. T. and Peterson, J. W., "An Interindustry Model of Utah", *Review of Economics and Statistics*, November, 1956.

North, Douglas C., "Location Theory and Regional Economic Growth", *Journal of Political Economy*, June, 1955.

Steiner, Robert L., "Urban and Inter-Urban Economic Equilibrium", *Land Economics*, May, 1956.

Tiebout, Charles M., "The Urban Economic Base Reconsidered", *Land Economics*, February, 1956.

Vining, Rutledge, "Regional Variation in Cyclical Fluctuation Viewed as a Frequency Distribution", *Econometrica*, July, 1945.

——, "Location of Industry and Regional Patterns of Business Cycle Behavior", *Econometrica*, January, 1946.

——, "The Region as a Concept in Business-Cycle Analysis", *Econometrica*, July, 1946.

——, "The Region as an Economic Entity and Certain Variations to be observed in the Study of Systems of Regions", *American Economic Review, Papers and Proceedings of the American Economic Association*, May, 1949.

Articles on Petroleum

Alberta Society of Petroleum Geologists, "Northern Alberta Oil Sands", *Bulletin of American Association of Petroleum Geologists*, February, 1951.

Ball, Max W. (ed.), "Possible Future Oil Provinces of North America", *Bulletin of American Association of Petroleum Geologists*, February, 1951.

Beach, Floyd K., "History of Land Regulations and Land Grants in Western Canada", *Canadian Oil and Gas Industries*, May and June, 1954.

——, "Alberta's Petroleum Fraternity", *ibid.*, February, 1956.

Gilbert, Robert A., "Europe's Energy, Oil Outraces Coal as a Source of Power for the Continent", *Barron's* (weekly), June 18, 1956.

Haskett, Irene, "Reservoir Analysis of the Redwater Pool", *Canadian Oil and Gas Industries*, July, 1951.

Lahee, Frederic H., "Degrees of Success in Wildcat Drilling", *Bulletin of American Association of Petroleum Geologists*, January, 1951.

Link, T. A. and Moore, P. D., "Structure of Turner Valley Gas and Oil Field, Alberta", *ibid.*, November, 1934.

Link, T. A., "Tectonic Features of Western Canada", *ibid.*, May, 1946.

——, "Interpretations of Foothills Structure, Alberta, Canada", *ibid.*, September, 1949.

——, "Theory of Transgressive and Regressive Reef (Bioherm) Development and Origin of Oil", *ibid.*, February, 1950.

——, "Source of Oil in 'Tar Sands' of Athabasca River, Alberta, Canada", *ibid.*, April, 1951.

Lockwood, R. P. and Erdman, O. A., "Stettler Oil Field, Alberta, Canada", *ibid.*, April, 1951.

Sproule, J. C., "Origin of McMurray Oil Sands, Alberta", *ibid.*, September, 1938.

Waring, W. W. and Layer, D. B., "Devonian Dolomitized Reef, D-3 Reservoir, Leduc Field, Alberta, Canada", *ibid.*, February, 1950.

Weber, George, "Petrochemicals in the Southwest", *Oil and Gas Journal*, May 3, 1951.

Periodicals and Newspapers

Calgary *Albertan*

Calgary *Herald*

Canadian Gas Journal

Canadian Oil Journal

Canadian Oil and Gas Industries

Daily Oil Bulletin

Edmonton *Journal*

Imperial Oil Review

Myers Oil Weekly

Oil in Canada

The Financial Post

The Oil and Gas Journal

The Oil and Gas Journal Supplement, W. L. Nelson, *Cost-Imating*

Western Business and Industry

Western Oil Examiner

World Oil

World Petroleum

Annual Petroleum Publications

American Gas Association, *Gas Facts*, New York.
American Petroleum Institute, *Petroleum Facts and Figures*, New York.
Canadian Oil and Gas Directory (C. O. Nickle and A. R. Smith).
Canadian Petroleum Association, *Statistical Year Book*, Calgary.
De Golyer and MacNaughton, *Twentieth Century Petroleum Statistics*, Dallas, Texas.
Imperial Oil Limited, *Facts and Figures about Canadian Oil*, Toronto.
James Richardson and Sons, *Western Canadian Oils, including Natural Gas Review*, Winnipeg.
The Financial Post, *Survey of Oils.*
The Independent Petroleum Association of America, *The Oil Producing Industry in Your State*, Tulsa, Oklahoma.
United States Bureau of Mines, *Minerals Yearbook*, Washington, D.C.
World Petroleum Statistics.

Government Documents and Publications

GOVERNMENT OF CANADA

(a) MONOGRAPHS AND REPORTS (DBS)

Canada Year Book (annual).
Canada's International Investment Position, 1926-1954.
Census of Canada, 1941, 1951 and *1956.*
Census of the Prairie Provinces, 1946.
Construction in Canada, 1953-55.
Consumption of Petroleum Fuels.
Handbook of Agricultural Statistics, Parts I-III.
Labour Force, November 1945-January 1955.
Manufacturing Industries of Canada.
National Accounts, Income and Expenditure, 1926-1950 and *1950-1956.*
Refined Petroleum Products.
Retail Trade, 1930-1951.

(b) ROYAL COMMISSION REPORTS

Report of the Royal Commission on Dominion Provincial Relations, Ottawa, 1940 (reprint, 1954).
Royal Commission of Canada's Economic Prospects (Gordon Commission), *Preliminary Report*, Ottawa, December, 1956.

(c) ANNUAL REPORTS

Department of Labour, *Wage Rates and Hours of Labour in Canada.*
Department of Mines and Technical Surveys, *Canadian Mineral Industry.*
——, *Coal in Canada.*
——, *Natural Gas in Canada.*
——, *Petroleum in Canada.*
Department of National Revenue, *Taxation Statistics.*
Department of Northern Affairs and National Research, *Annual Reports.*
Department of Public Works, *Annual Reports.*
Department of Trade and Commerce, *Annual Reports.*
——, *Private and Public Investment in Canada.*
Public Accounts of Canada.

A large number of annual and monthly reports of the DBS on Canadian industries were consulted and utilized. The reader is referred to *Canadian Government Publications*, annual catalogues.

GOVERNMENT OF ALBERTA

Alberta's Economic Prospects, Submission to the Royal Commission on the Economic Prospects of Canada, Queen's Printer, Edmonton, December, 1955.
Budget Speeches, 1946-57.
Department of Industries and Labour, Provincial Bureau of Statistics, *Employment Statistics and Expenditure of Firms Engaged in the Development of Alberta Resources, 1951-55.*
——, *Facts and Figures-Alberta*, Queen's Printer, Edmonton, 1954.
——, *Summary of General Statistics* (monthly).
Department of Mines and Minerals, *Annual Reports.*
Oil Sands Project, *Proceedings, Athabasca Oil Sands Conference, September 1951*, Edmonton, 1951.
Petroleum and Natural Gas Conservation Board, *Alberta Oil and Gas Industry*, annual reports.
——, *Annual Review of the Oil and Gas Industry,* annual reports.
——, *Schedule of Wells Drilled,* annual since 1949.
Public Accounts, 1946-57.
Report of the Royal Commission on the Development of Calgary and Edmonton, Queen's Printer, Edmonton, January 1956.

Index

Alberta, Western Canada, Canada, Calgary and Edmonton have not been indexed separately except for isolated entries.